APF ENERGY TRUST

2003

ANNUAL REPORT

By the Numbers

Last year...

- **164:** Number of wells drilled in which APF participated
- **82%:** Replacement of production through the drill bit
- **$33.6 million:** Total capital expenditures, representing 40% of cash flow
- **$167 million:** Value of mergers and acquisitions
- **50%:** Total return enjoyed by unitholders

Since inception...

- **22%:** Average annual rate of return
- **1,471%:** Increase in enterprise value
- **$1.98:** Average annual cash distribution per unit on original $10 IPO
- **85%:** Average distribution payout ratio
- **15:** Major corporate or asset acquisitions

APF Energy Trust is a dynamic, growth-oriented royalty trust created in December, 1996 to provide unitholders with stable distributions based on cash flow generated from high quality oil and gas properties. Through strong acquisitions and effective optimization initiatives, APF has increased production by more than 665%, from 1,700 boe/d in the fourth quarter of 1996 to more than 13,000 boe/d at December, 2003. Since completing its initial public offering at $10 per unit, the Trust has declared cumulative distributions of $13.83 per unit to December, 2003, rewarding unitholders with an average annual return of 22%.

TRADING HISTORY

APF Energy Trust units ("AY.UN") and convertible debentures ("AY.DB") are traded on the Toronto Stock Exchange. Average daily trading volumes for the units increased by 137% from 67,000 in 2002 to 163,000 in 2003. The following graph illustrates trading in APF's units since inception.

ANNUAL AND SPECIAL MEETING

The Annual and Special Meeting of the Unitholders of APF Energy Trust will be held on May 18, 2004 at 3:00 pm in the Roxy Theatre at the Sun Life Conference Centre (mezzanine level), 140 – 4th Avenue S.W., Calgary, Alberta.

CONTENTS

Summary of Operating and Financial Results

Year Ended December 31	2003	2002	% Change
Financial			
($000, except per unit/boe amounts)			
Revenue	**165,457**	94,021	76%
Per unit basic	**$5.34**	$4.59	16%
Per unit diluted	**$4.64**	$4.58	1%
Operating cash flow (1)	**83,326**	43,788	90%
Per unit basic	**$2.69**	$2.14	26%
Per unit diluted	**$2.34**	$2.13	10%
Net earnings (2)	**43,048**	11,365	279%
Per unit basic	**$1.32**	$0.55	140%
Per unit diluted	**$1.21**	$0.55	120%
Distributions declared	**68,713**	37,766	82%
Per unit	**$2.195**	$1.81	21%
Operating costs per boe	**$7.12**	$6.35	12%
Operating netbacks per boe	**$22.11**	$17.83	24%
Bank debt	**98,000**	88,000	11%
Units outstanding (000)			
End of period	**34,074**	22,942	49%
Weighted average - basic	**30,970**	20,470	51%
Weighted average - diluted	**35,641**	20,528	74%
Trading			
High ($)	**$12.67**	$11.19	13%
Low ($)	**$9.30**	$9.00	3%
Close ($)	**$12.54**	$9.79	28%
Average daily volume	**163,000**	68,700	137%
Operating			
Daily production (average)			
Oil (bbl)	**6,472**	5,307	22%
Gas (mcf)	**33,799**	18,488	83%
NGL (bbl)	**358**	144	149%
Total (boe) (3)	**12,463**	8,532	46%
Commodity prices			
Oil (per bbl)	**$34.46**	$33.66	2%
Gas (per mcf)	**$6.32**	$3.83	65%
NGL (per bbl)	**$31.82**	$25.15	27%
Average (boe) (3)	**$35.95**	$29.65	21%
Proved plus probable reserves (4)			
Oil & NGLs (mbbl)	**23,789**	20,608	15%
Gas (mmcf)	**99,197**	68,290	45%
Total (mboe)	**40,322**	31,989	26%
Drilling (gross wells)			
Gas	**80**	62	29%
Oil	**60**	40	50%
Coalbed methane	**19**	–	100%
Other	**5**	7	(29%)
Total	**164**	109	50%

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and accrued interest on convertible debentures.

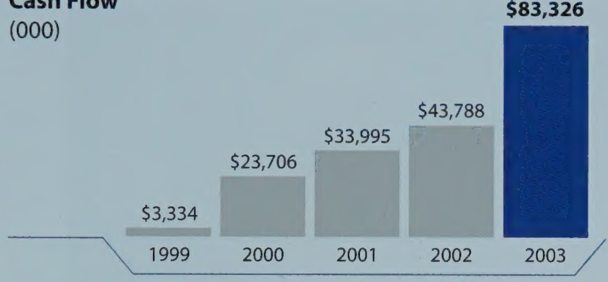
(2) Net income in the basic per trust unit calculation has been reduced by interest accrued on the convertible debentures.

(3) Boe's may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a boe conversion ratio for natural gas of 6 mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

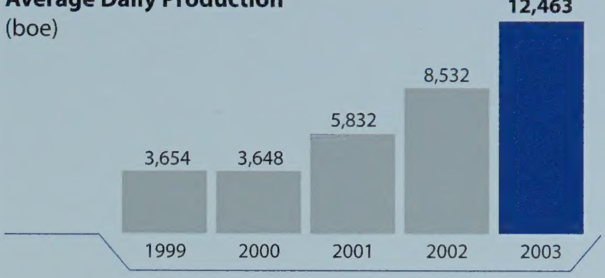
(4) 2002 reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

Key Performance Data

Cash Flow
(000)



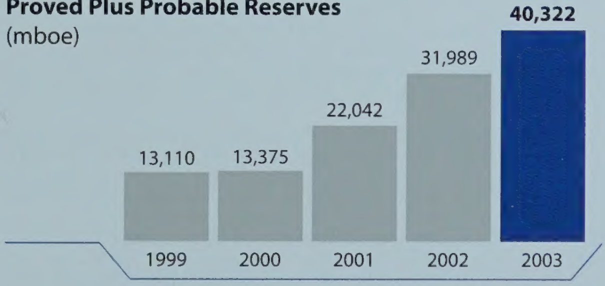
Average Daily Production
(boe)



STRONG

Cash Flow
(per boe)

Proved Plus Probable Reserves
(mboe)

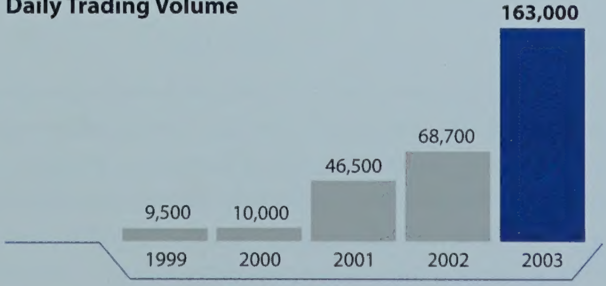


GROWTH

Key Performance Data

Distributions
(per unit)

Daily Trading Volume



Message To Unitholders

Strong acquisitions, effective development and a buoyant commodity price environment drove APF to another successful year, with unitholders experiencing more than a 50% total return. Since inception, APF has delivered an average annual return of 22%, placing us among the industry leaders.

Martin Hislop
Chief Executive Officer

In last year's annual report, we remarked how the mergers and acquisitions market was shaping up to present a challenge for trusts that had been particularly effective at growing their businesses in recent years through the purchase of corporations and assets. That being said, APF had its most active year ever, executing on $167 million of transactions, adding further development potential to its inventory of drilling prospects. We strongly believe that we maintained our discipline of not over-paying for assets and look forward to harvesting the value from these new properties.

Interestingly, the challenge remains the same for 2004: finding assets and corporations that are not over-priced. With the impressive performance of the royalty trust sector over the last few years in a continued low interest rate environment, the group has flourished. But there has been a price for that popularity. A number of new names are now in the space competing for the same merger and acquisition opportunities. In 2003 alone, nine new trusts were created, bringing the total group to 26, considerably more than the 11 royalty trusts that were operating at the end of 2001. Compounding the challenge is that the historical raw material for acquisitions, being junior oil and gas companies, are trading at multiples even higher than many trusts. The management teams guiding these start-ups to such strong valuations, who had been successful in previous years selling their last ventures to the trusts, find themselves looking for an exit, but with fewer trusts willing to pay the price. Some will stay the course and diligently work their assets through the drill bit; some will be sold; and some will continue to grow through the cycle, either competing with the trusts for acquisitions or themselves converting into trusts.

In any event, the APF business plan is not to rely on the M&A function to maintain the stability of or our asset base, but to focus more on the drill bit as a value driver. During the four-year period from 2000 to 2003, APF replaced an average

1996

■ Completed $35 million IPO at $10 per unit in December and acquired initial properties for $21 million ■ Year-end production was 1,700 boe/d.

1997

■ Executed first major transaction, the corporate purchase of Bayridge Resources, for $24 million only three months after IPO ■ Acquired additional assets in core area of Countess.

1998

■ Raised $18 million of new equity in first financing since IPO ■ With oil averaging $U.S. 14.42 per bbl on the year, APF identified a buying opportunity and acquired long-life light oil assets in the Central and Southern Alberta areas for a total of $27 million ■ Despite low commodity prices, APF distributed $1.85 per unit ■ Annual production averaged 3,673 boe/d.

of 106% of its production through drilling and optimization initiatives, perhaps the only trust to have done so.

While maintaining a reasonable risk profile, APF intends to be an even more active driller, which requires two things: human capital and opportunity.

Recognizing the need to generate internal prospects that have the potential to add greater value than acquisitions, APF has added key technical staff across all its core areas. Currently, the Trust has eleven geologists on staff complemented by three part-time geophysicists. On the operations and engineering side, APF has ten professionals. Both the geoscience and operations groups are supported by various office and field staff. Our technical team has been tasked with finding and creating value for APF unitholders however it might be found: by identifying upside as part of an acquisition; to optimizing existing production; to expanding known pools; to grass-roots initiatives that result in new discoveries.

APF's commitment to this effort and the extent to which opportunity has been provided is reflected in a variety of ways.

Firstly, all of the assets acquired by the Trust have come with upside potential. Some of that had already been recognized at the time of purchase and will be captured through development. This is the low-hanging fruit that is usually harvested within 12 to 18 months of an acquisition. But other layers of opportunities continue to be found and will be turned to account in the coming years. An example is APF's coalbed methane ("CBM") strategy, which was created through the corporate acquisition of CanScot Resources Ltd. in September, 2003. CBM has been a proven resource in the United States for many years and is now poised to make a significant impact on the western Canadian gas scene.

Steven Cloutier
President and Chief Operating Officer

With CanScot's technical team now part of APF, our Trust is uniquely positioned among its peers to take advantage of a potentially tremendous long-life resource that will be developed over a three to five year period.

Secondly, APF is becoming more active at the front end of the drilling equation, by increasing its land acquisition and seismic activity. While lower-risk development and infill drilling has been APF's bread and butter over the last few years, we felt strongly that we needed to expose ourselves to a more dynamic range of opportunities and the best way to accomplish that was through grass roots initiatives. APF's staff has been challenged to not only make the most of what it currently manages, but to find new areas for growth.

APF's 2004 capital budget has been set at approximately $40 million, with the potential to exceed that, should we identify new ideas that will add value. Funding will come from a variety of sources, the first of which will be cash flow.

1999

■ *With an inventory of drilling prospects established, APF began to outline the development program that would result in four consecutive years of replacing at least 100% of production through drilling and optimization* ■ *Without any significant acquisitions, APF's production remained steady at 3,654 boe/d.*

2000

■ *Completed new equity issue, raising $8.9 million to fund increased capital expenditure program* ■ *Continued development of assets replaced 107% of annual production* ■ *Asset swap at end of the year created new gas core area for APF at Redwater in Central Alberta* ■ *Daily production averaged 3,648 boe.*

2001

■ *APF spent $115 million on acquisition and development initiatives, increasing production by 60% to 5,832 boe/d* ■ *Corporate acquisition of Alliance Energy and follow-on purchase of Marathon Canada'a assets established strong platform for growth in Southeast Saskatchewan* ■ *A total of $66 million was raised in two public financings* ■ *Annual distributions amounted to a record $3.04 per unit.*

Since completing its IPO, APF has been among the industry leaders in withholding a portion of cash flow to provide capital for drilling, development and optimization. In aggregate since inception, APF has paid out 85% of cash flow. Going forward, we're targeting a payout range of 80% to 90% for the year. The payout ratio may vary from month to month, but we are nonetheless committed to withholding a meaningful portion of cash flow.

The second source is APF's recently launched Premium Distribution Reinvestment Plan ("DRIP"). With a 40% participation rate, the DRIP will contribute significantly to the capital program, with \$2.5 to \$3.0 million of equity being issued each month.

APF's internal estimates indicate that the results of the capital program will maintain a stable production profile through 2004.

In conjunction with our development and optimization initiatives, we will continue to identify and evaluate potential acquisitions. While our target range would be transactions between \$25 and \$50 million, we have the resources and access to capital that would allow us to execute on an opportunity as large as \$350 million. But as we have stated in the past: we are determined to execute on acquisitions only if the right opportunity materializes.

We want to thank our employees, consultants and contractors for all of their hard work during 2003, and our Board of Directors for their guidance.

Martin Hislop
Chief Executive Officer

Steven Cloutier
President and Chief Operating Officer

February 20, 2004
Calgary, Alberta

2002

■ APF strengthened its presence in Southeast Saskatchewan with the purchase of Kinwest Resources and its joint venture partner for \$59.5 million ■ Acquired assets at Paddle River, Alberta for \$22.7 million, expanding APF's gas operations in Central Alberta ■ Daily production averaged 8,532 boe.

2003

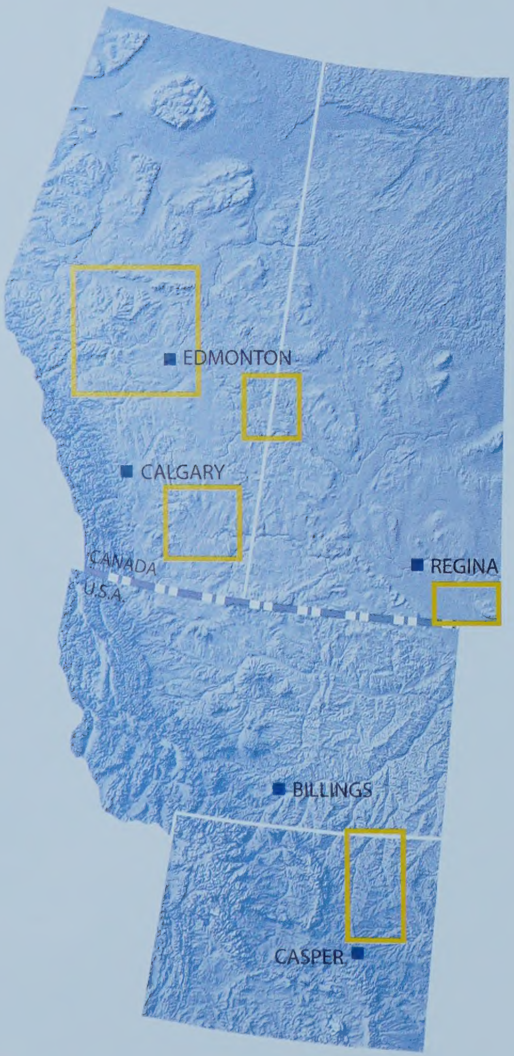
■ APF completed three corporate and several asset acquisitions for a total of \$167 million, increasing the production base in Southern and Central Alberta ■ The Trust established a coalbed methane group through the purchase of CanScot Resources ■ Raised more than \$100 million in new equity and issued a \$50 million convertible debenture ■ Management internalized ■ Daily production averaged 12,463 boe and unitholders enjoyed a 50% total return.

Operations Review

APF participated in the drilling of 164 (64.8 net) wells with a 100% success rate in 2003. Capital expenditures of $33.6 million, or 40% of cash flow, were directed to development and optimization initiatives with results replacing 82% of annual production. Production volumes increased by 46% to 12,463 boe/d.

Development and Optimization

Left to right: Dan Allan, VP Coalbed Methane; Bonnie Nicol, VP Operations; John Ewing, VP GeoScience; Ken Pretty, VP Corporate Development and Land



Taking advantage of an opportunity-rich inventory of drilling prospects and a technical team deep in experience, APF's development and optimization program reached record levels during 2003. In total, the Trust participated in 164 (64.8 net) wells with a 100% success rate. Capital expenditures in 2003, excluding acquisitions, totalled $33.6 million and resulted in proved plus probable reserves additions of 3,720 mboe, replacing 82% of APF's 2003 annual production, as the drill bit continued to maintain the stability of the APF asset base. Over the past four years, APF has replaced an average of 106% of annual production through development initiatives, one of the strongest reserve replacement track records in the sector.

APF's operations are divided into five Business Units: Southern Alberta; Central Alberta; East Alberta/Heavy Oil; Southeast Saskatchewan; and Coalbed Methane. Each Business Unit is comprised of technical and business professionals and support staff whose mandate is to increase the value of the assets under their management through a combination of development, exploration, optimization and acquisitions.

SOUTHERN ALBERTA

The Southern Alberta Business Unit is responsible for two general areas, most of which is operated: the Countess property, which APF acquired as part of its initial public offering in 1996; and the assets acquired on the takeover of Nycan Energy in April, 2003. This area is prospective for shallow gas in many horizons, including the Belly River, Milk River, Medicine Hat and Second White Specks formations. APF also holds deeper rights on a number of its properties.

Fourth quarter production in the Southern Alberta Business Unit was comprised of 15 mmcf/d of gas and 440 bbl/d of oil and natural gas liquids.

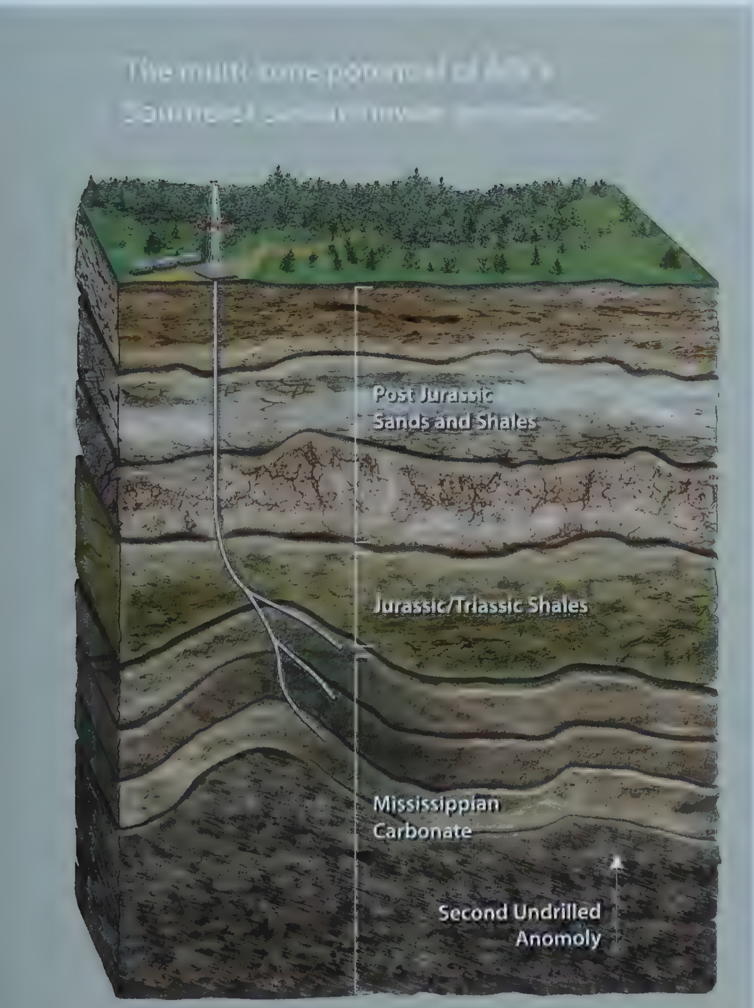
Drilling at Countess was extensive in 2003, with development initiatives replacing 100% of production on a proved plus probable basis. In total, APF drilled 38 (28.2 net) gas wells, predominantly in the Milk River and Medicine Hat zones.

The corporate acquisition of Nycan brought a large suite of contiguous multi-zone assets located southwest of the Countess field. During 2003, APF participated in seven (1.7 net) wells on the Nycan lands.

Mike Davies

Jiun (Shig) Shigematsu

The 2004 budget contemplates total capital expenditures in the Southern Alberta Business Unit of $8 million, with 54 gross wells targeting a variety of shallow and deeper horizons.



Note: Not to scale

EAST ALBERTA AND HEAVY OIL

The Hawk Oil acquisition in February, 2003 provided APF with a new heavy oil platform along the Alberta/Saskatchewan border. During the year, the Trust drilled seven wells into a new pool at South Epping, which is now being considered for waterflood.

Total production from this Business Unit averaged 2,147 boe/d during the fourth quarter of 2003, with heavy oil accounting for 1,300 bbl/d, or 10% of the total APF portfolio. With high oil prices and a reasonable differential from light quality crude, APF views its heavy oil assets as providing solid cash flow with upside potential.

Total capital expenditures for the East Alberta/Heavy Oil Business Unit are expected to amount to $1.4 million in 2004, covering the drilling of five wells.

CENTRAL ALBERTA

Central Alberta has been an active area for APF, as acquisitions and development initiatives pushed fourth quarter average production to 3,700 boe/d, comprised of 14 mmcf of gas and 1,370 bbl of oil and NGLs. With tremendous multi-zone potential, this area will continue to play an important role in APF's development and optimization strategy.

Total capital expenditures in 2003 amounted to $8.6 million, as the Trust participated in 48 (9.8 net) wells in areas such as Paddle River, Leaman, Pembina and Redwater.

For 2004, the APF budget contemplates $9.2 million of capital to be spent on seismic, land acquisition and the drilling of 25 gross wells.

SOUTHEAST SASKATCHEWAN

APF's largest oil producing area is Southeast Saskatchewan, where light gravity crude is produced predominantly from the Frobisher, Midale and Alida formations. Since acquiring its initial interests in the area in 2001, APF has been very effective in executing both corporate development initiatives as well as its drilling strategies. In particular, the use of 3D seismic to delineate opportunities in under-exploited pools has proven very successful.

2003 capital expenditures of $11.1 million resulted in [illegible] gross (9.1 net) horizontal oil wells and one vertical stratigraphic test. At Queensdale, APF drilled four (2.4 net) horizontal wells and replaced 260% of production. During the year, APF acquired minor partner interests and one quarter section of land, offsetting APF operated production. The acquisition set up five (4.8 net) horizontal locations which have been included in the 2004 drilling program.

Fourth quarter 2003 production averaged 4,100 boe/d, of which 96% was oil. In addition to Queensdale, active production and development areas in this Business Unit include Tatagwa and Macoun.

For 2004, a budget of $14.1 million has been allocated to the drilling of 20 gross wells.

Alison Banda

Rick James

Drilling Activity

Years Ended December 31	**2003**		2002		2001		2000	
	Gross	**Net**	Gross	Net	Gross	Net	Gross	Net
Oil	**60**	**19.4**	40	12.0	40	8.9	33	3.2
Gas	**80**	**40.2**	62	33.0	33	31.3	65	14.8
CBM	**19**	**4.4**	–	–	–	–	–	–
Other	**5**	**0.8**	7	1.7	1	0.1	27	0.5
Dry and abandoned	–	–	–	–	2	2.0	–	–
Total	**164**	**64.8**	109	46.7	76	42.2	125	18.5
Success rate		**100%**		100%		95%		100%

Capital Expenditures

Years Ended December 31 ($000)	**2003**	2002	2001	2000	1999
Corporate and asset acquisitions	**164,550**	90,101	105,717	13,249	3,895
Land acquisitions	**2,310**	616	239	147	143
Seismic	**1,070**	497	208	15	99
Drilling and completion	**24,287**	15,890	12,490	3,912	2,232
Production facilities	**7,749**	3,684	3,340	1,619	950
Other	**494**	908	(52)	–	5
Subtotal	**200,460**	111,696	121,942	18,942	7,324
Dispositions (including swaps)	**(9,284)**	(10,569)	(6,903)	(12,393)	(2,326)
Net capital expenditures	**191,176**	101,127	115,039	6,549	4,998

Finding and Development Costs ("F&D")(1)

Proved plus probable (3)

($000)

	2003	2002	2001
Total F&D	**$ 33,601**	$ 21,595	$ 16,225
Change in future development	**$ 27,875**	$ 11,525	$ 5,625
Total	**$ 61,476**	$ 33,120	$ 21,850
Net reserve additions (mboe)(2)	**3,002**	4,054	2,690
($/boe except recycle ratio values)(2)			
F&D cost	**$ 20.48**	$ 8.17	$ 8.12
Operating netback	**$ 22.11**	$ 17.83	$ 20.42
Recycle ratio	**1.08**	2.18	2.51
Rolling three year average F&D cost	**$ 11.95**	$ 7.88	$ 9.49
Rolling three year average Netback	**$ 20.12**	$ 19.84	$ 17.27
Rolling three year average recycle ratio	**1.68**	2.52	1.82

Finding, Development and Acquisition Costs ("FD&A")(1)

Proved plus probable (3)

($000)

	2003	2002	2001
Total FD&A	**$ 33,601**	$ 21,595	$ 16,225
Change in future development	**$ 27,875**	$ 11,525	$ 5,625
Net acquisitions	**$ 157,576**	$ 79,532	$ 98,814
Total	**$ 219,052**	$ 112,652	$ 120,664
Net reserve additions (mboe)(2)	**12,881**	13,064	10,740
($/boe except recycle ratio values)(2)			
FD&A cost	**$ 17.02**	$ 8.62	$ 11.24
Operating netback	**$ 22.11**	$ 17.83	$ 20.42
Recycle ratio	**1.30**	2.07	1.82
Rolling three year average FD&A cost	**$ 12.33**	$ 9.59	$ 11.66
Rolling three year average Netback	**$ 20.12**	$ 19.84	$ 17.27
Rolling three year average recycle ratio	**1.63**	2.07	1.48

(1) The aggregate of the exploration and development costs incurrred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(2) Boe's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) Reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties for 2002 and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

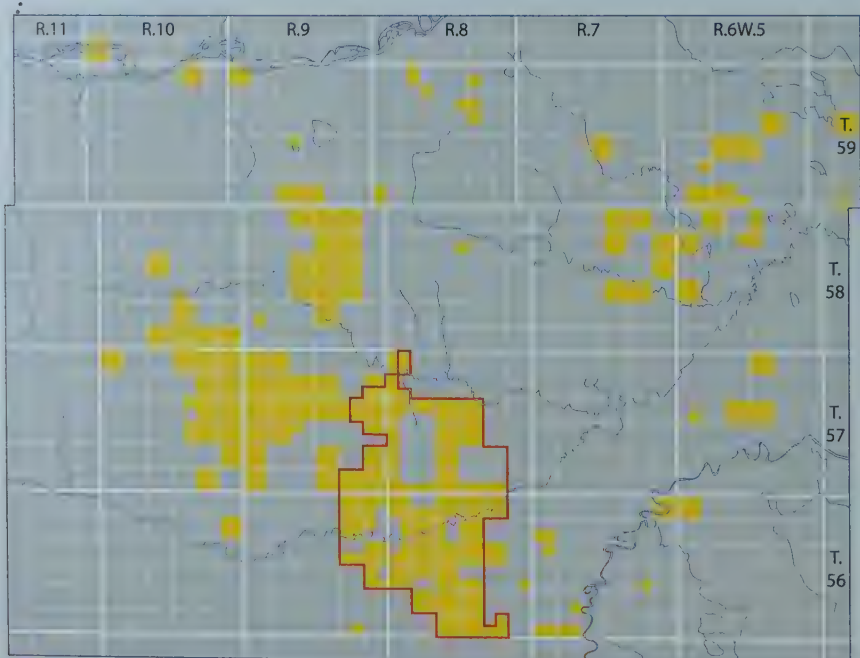
Redwater

Product		Sweet natural gas
Year acquired		2000
Net undeveloped acres		36,305
Working interest		53%
P+P reserves (mboe)		1,508
Average 2003 boe/d		855
2003 drilling	Gross	Net
Oil	0	0.0
Gas	6	6.0
Total	6	6.0
2003 CapEx		$4.7 million

APF Land

Central Alberta

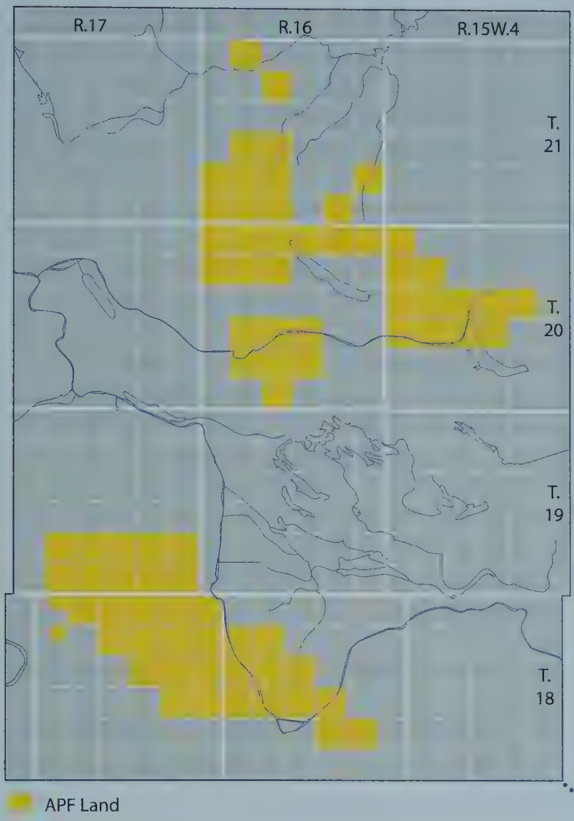
APF assets located in the Central Alberta region have multi-zone potential in wells being drilled to depths of 200 to 1,700 metres. APF utilizes seismic data to define the structural and stratigraphic traps. Assets in this area are currently being exploited for their gas production with key horizons at the Cretaceous Mannville and Jurassic Nordegg formations.



APF Land — Paddle River Gas Unit

Paddle River

Product		Natural gas and oil
Year acquired		2002
Net undeveloped acres		25,888
Working interest		61%
P+P reserves (mboe)		1,240
Average 2003 boe/d		827
2003 drilling	Gross	Net
Oil	3	0.6
Gas	1	0.5
Total	4	1.1
2003 CapEx		$2.9 million



Countess

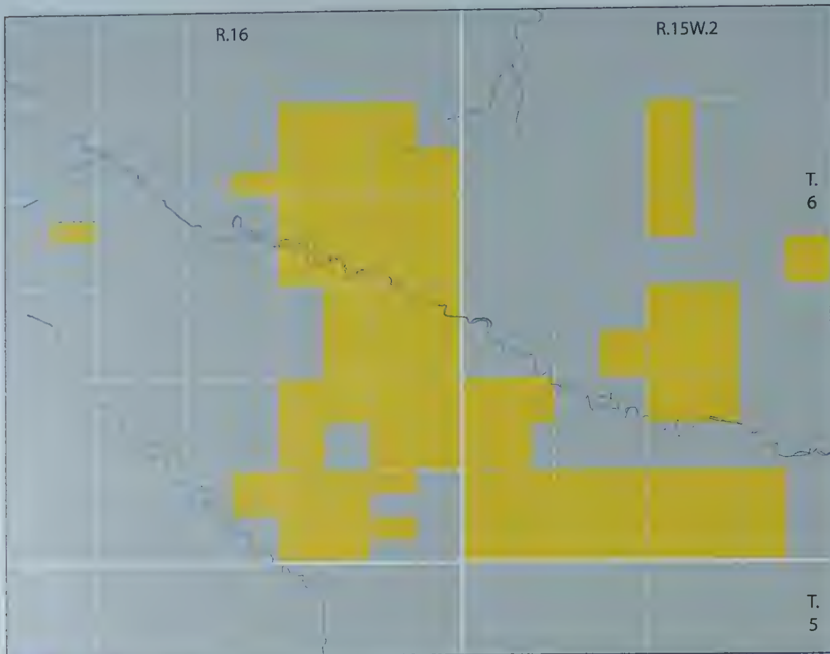
Product		Sweet natural gas
Year acquired		1996-97
Net undeveloped acres		405
Working interest		87%
P+P reserves (mboe)		5,893
Average 2003 boe/d		1,720
2003 drilling	Gross	Net)
Oil	0	0.0
Gas	38	28.2
Total	38	28.2
2003 CapEx		$7.8 million

Southern Alberta

The Southern Alberta region is characterized by predominately shallow gas production. The primary producing zones include the Milk River, Medicine Hat and Second White Specks formations. The 2003 acquisition of Nycan also increased APF's exposure to Mannville oil and gas production.

Turin/Retlaw

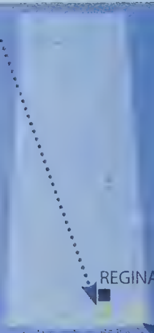
Product		Natural gas and oil
Year acquired		2003
Net undeveloped acres		49,451
Working interest		46%
P+P reserves (mboe)		1,673
Average 2003 boe/d		504
2003 drilling	Gross	Net
Oil	1	0.0
Gas	6	1.7
Total	7	1.7
2003 CapEx		$1.8 million



APF Land

Tatagwa

Product	Medium oil	
Year acquired	2001	
Net undeveloped acres	2,508	
Working interest	57%	
P+P reserves (mboe)	2,159	
Average 2003 boe/d	838	
2003 drilling	Gross	Net
Oil	4	2.9
Gas	0	0.0
Total	4	2.9
2003 CapEx	$2.52 million	

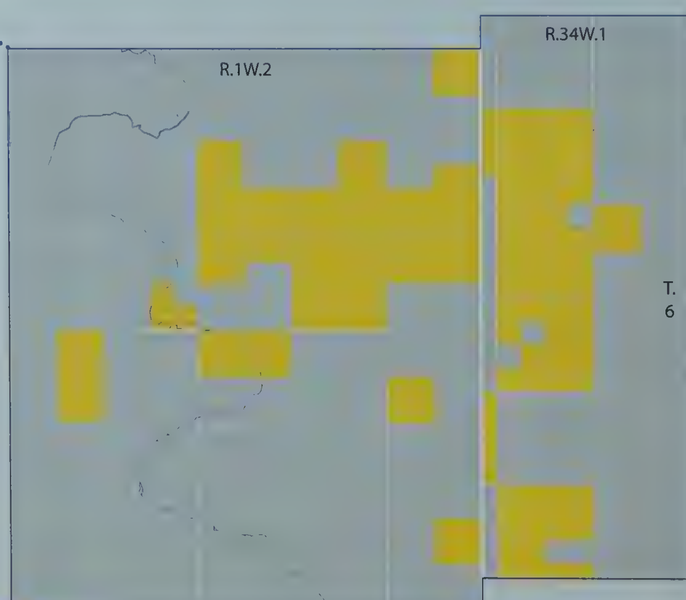


Southeast Saskatchewan

Light oil production in this region is primarily from Mississippian carbonate reservoirs. The key productive horizons are the Alida and Midale beds. Extensive use of 3D seismic combined with horizontal drilling technology is utilized to optimize assets in this region.

Queensdale

Product	Light oil	
Year acquired	2001	
Net undeveloped acres	12,315	
Working interest	50%	
P+P reserves (mboe)	2,143	
Average 2003 boe/d	975	
2003 drilling	Gross	Net
Oil	5	3.0
Gas	0	0.0
Total	5	3.0
2003 CapEx	$2.70 million	



APF Land

Coalbed Methane

In September, 2003, APF completed the acquisition of CanScot Resources Ltd., a Calgary-based oil and gas company with coalbed methane ("CBM") operations in Alberta and Wyoming. The CanScot acquisition provided APF with an entry into the CBM business and created a platform from which to execute this exciting new strategy.

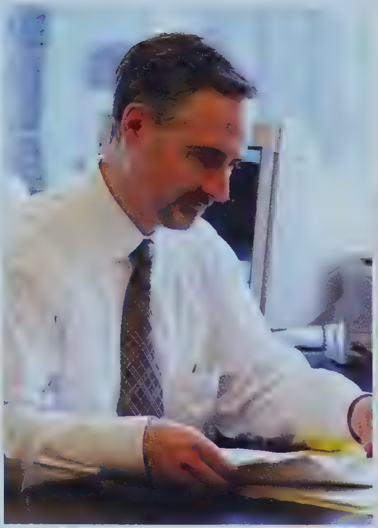
WHAT IS CBM?

CBM is natural gas produced from coal seams. This is accomplished through a reduction of reservoir pressure within the coal and is normally achieved by pumping out water. In a coal seam, natural gas is bound to the coal by molecular forces. When the pressure is released through dewatering, gas is liberated. The structure of the coals allows them to hold approximately six times the volume that can be held in a conventional reservoir.

THE OPPORTUNITY

The development of CBM is in its infancy in Canada. It is a very important energy source in the U.S. where current production accounts for close to 10% of domestic natural gas production. As the Western Canadian Sedimentary Basin rapidly matures, the need to replace production with unconventional supply is creating new opportunities. The development of CBM in particular will be a critical factor in allowing Canada to maintain current rates of natural gas production.

The estimates for Canadian CBM reserves are substantial. The Geological Survey of Canada believes there is between 180 tcf and 550 tcf of gas in place within the country's coals. Of equal importance, the Alberta Plains, the largest geographic area for CBM potential, are estimated to contain between 115 tcf and 350 tcf of gas in place. For perspective, the volume of undiscovered conventional gas in place is estimated at approximately 250 tcf, thus making CBM a critical resource for the future energy development of the country.



Jeff Shaw

Mark Livingstone

OUR EXPERTISE

With the acquisition of CanScot, APF established itself as a producer and developer of CBM, both in Canada and the United States. APF's CBM team has been actively involved in the development of numerous projects in the Powder River Basin of Northeast Wyoming and has established commercial production from several fields. The Powder River Basin is the most active U.S. CBM area and the results have been impressive. From an average of 6,000 mcf/d in 1994, CBM production has increased exponentially to a basin average of over 900 mmcf/d in 2003. This explosive growth has demonstrated the significant economic impact of CBM. APF believes that the experience acquired from these operations will be extremely valuable as the Trust begins to develop its CBM projects in Western Canada.

COALBED METHANE IN A ROYALTY TRUST PORTFOLIO

Several attributes of CBM reserves and production are well suited to an energy trust. Coal seams hold significantly more gas per unit area than conventional reservoirs, resulting in a longer reserve life. In addition, because coal seams often require a lengthy de-watering period, the typical CBM decline curve is more attractive than that of a conventional reservoir as CBM has a more gradual production decline.

Finally, and of equal importance, full scale CBM development is generally low risk. Once the higher risk initial pilot project has been determined to be commercial, the exposure associated with full scale development becomes relatively low. The ability to have a large number of low risk development locations makes CBM development attractive in a royalty trust portfolio.

POWDER RIVER BASIN

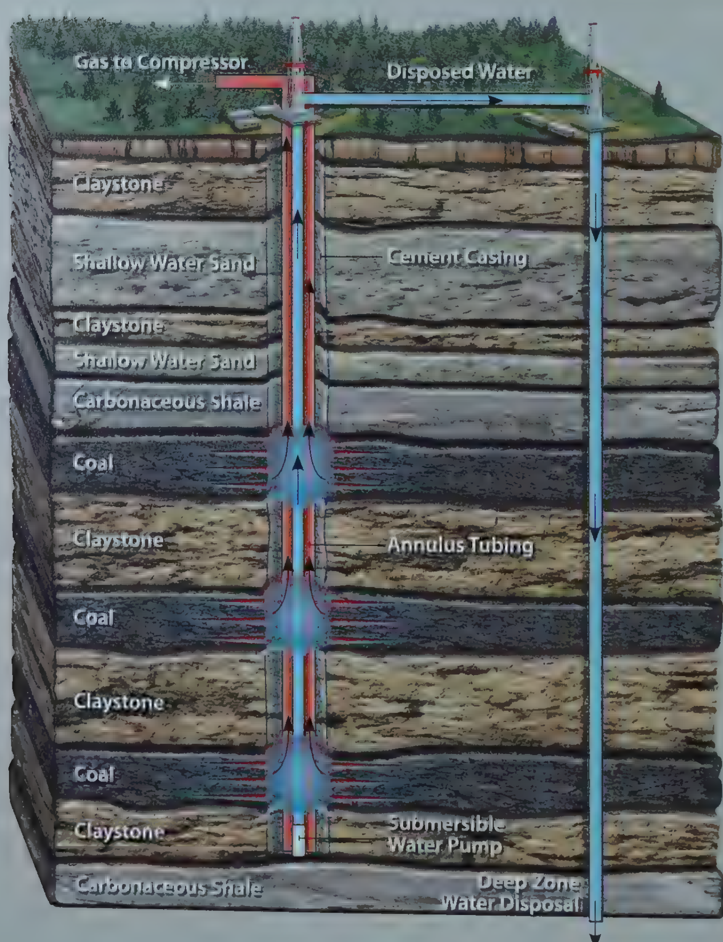
APF is currently active in six CBM projects in the Powder River Basin. Three of these fields are currently developed and producing gas. The remaining three projects are in the initial stages of development. The average cost to drill, case and complete a well in this area is approximately $U.S. 75,000.

[illegible] Draw

Thirty CBM wells have been drilled to date in this area, where APF has an average 23% working interest. These wells are completed in the Cook coal, which averages 11 metres in thickness at a depth of approximately 152 metres. Due to water discharge limitations, only 23 wells are currently on production. Gross production peaked at approximately 3,400 mcf/d, during the first quarter of 2003 and has now declined to approximately 2,000 mcf/d. An additional ten development locations are planned for drilling this year.

Kane

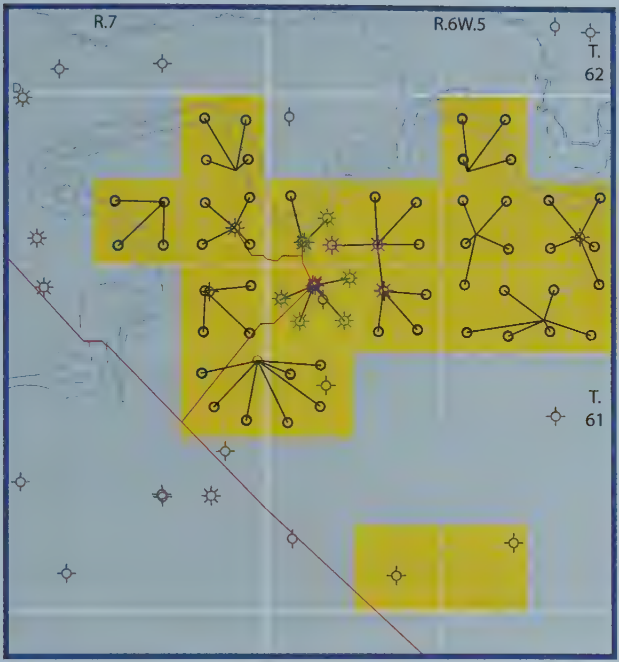
Fourteen CBM wells were drilled in late 2003 and are currently on production. These wells have been dually completed in both the Upper and Lower Wyodak coals, which average 11 metres in thickness per coal, at a depth of approximately 122 metres. As a result of the close proximity of adjacent production, many of these wells began producing gas immediately with a limited period of de-watering. Gross production is currently at 1,400 mcf/d and continues to increase as the coals are de-watered. An additional 30 locations have been identified for development over the next 18 months. APF's interests range from 16% to 25%.



Typical Alberta Coalbed Methane Well

Typical Upper Mannville CBM completion with multi-seam perforations and associated water disposal well into Devonian Wabamun formation

Note: Not to scale



APF Land — Natural Gas Pipeline

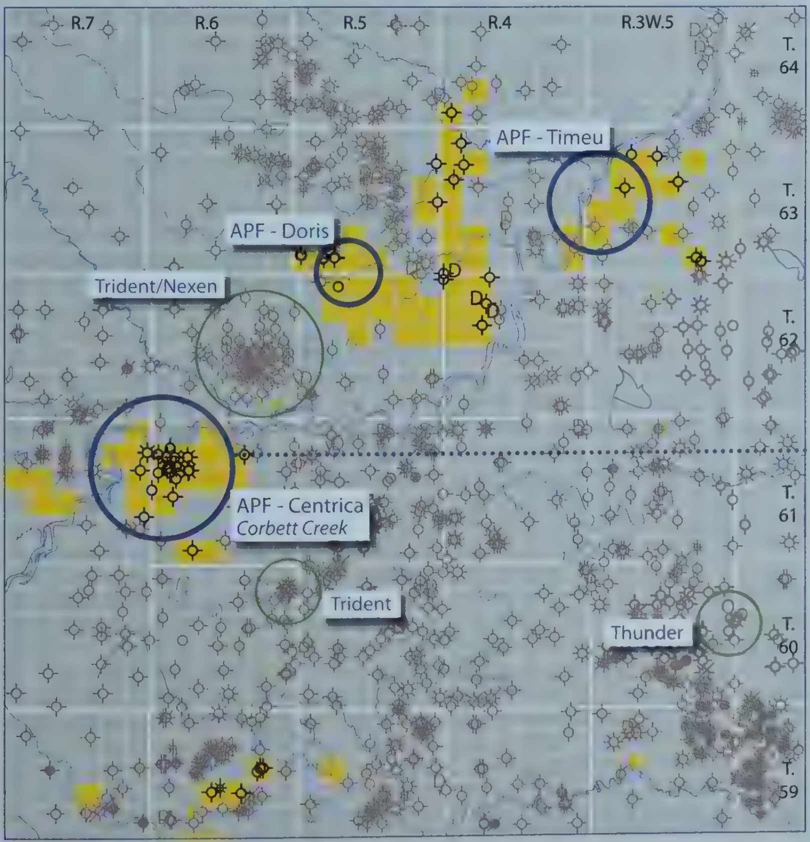
Corbett Creek

- Phase 1: 4 wells, 1 water disposal well
- Phase 2: 6 wells
- Phase 3: potential locations

Phase 1 was completed in 2003 and Phase 2 was completed in the first quarter of 2004. Phase 3 represents the full commercial potential for this area.

Corbett

The target coals occur within the Upper Mannville formation at a depth of approximately 1,000 metres and total coal thickness varies from six to eight metres in four separate coal seams. The two thickest coal seams have been targeted for exploitation.



APF Land — APF Pilot Project — Pilot Project

Greater Corbett Area

Product		Coalbed methane
Year acquired		2003
Net undeveloped acres		28,861
Working interest		66%
2003 drilling	Gross	Net
Coalbed methane	2	0.5
Total	2	0.5
2003 CapEx		$1.2 million

K-Bar

Twenty CBM wells have been drilled and are on production. Ten of these wells were completed in the Big George coal, which averages 12 metres in thickness at a depth of approximately 185 metres. Gross gas production peaked at [illegible]r 3,000 mcf/d during the second half of 2002 after twelve [illegible] of de-watering. Production volumes have slowly [illegible]d to current rates of approximately 2,000 mcf/d. [illegible] average 16% working interest in this area. The [illegible] ten wells were completed in the Wyodak coal, [illegible]rages eight metres in thickness at a depth of 244 [illegible] lower coal is exhibiting increasing gas produc[illegible]als continue to be de-watered.

[illegible]

[illegible]lated for development in 2004. With an 18% [illegible], an initial pilot project of eight wells is [illegible] be drilled by the end of the third quarter. [illegible] planned to be drilled for co-mingled produc[illegible] and Canyon coal seams, which average 7.6 [illegible]ckness at a depth of approximately 168 metres. [illegible]nd of drilling is planned on the same locations [illegible] production from the Wall and Pawnee coal [illegible] additional locations have been identified for [illegible] the next 24 months.

[illegible]

[illegible] largest interest at 70% and is manager of this [illegible] CBM project. Within the last few months, two test [illegible] been drilled to confirm gas content, structure [illegible] thickness. Based upon these results, an additional [illegible] will be drilled by the end of the second quarter. The [illegible]ht well pilot project should begin de-watering dur[illegible] third quarter of 2004. A second phase of 18 wells [illegible]anned for late 2004. Full scale development anticipates [illegible]r 90 CBM wells on this project by late 2005.

[illegible]

This project area is slated for an initial development of 16 wells in 2005. These wells will target the Big George coal, which is approximately 15 metres thick at a depth of close to 670 metres. Several pilot projects in the Big George coal, located to the east of this project area have demonstrated excellent results.

ALBERTA COALBED METHANE

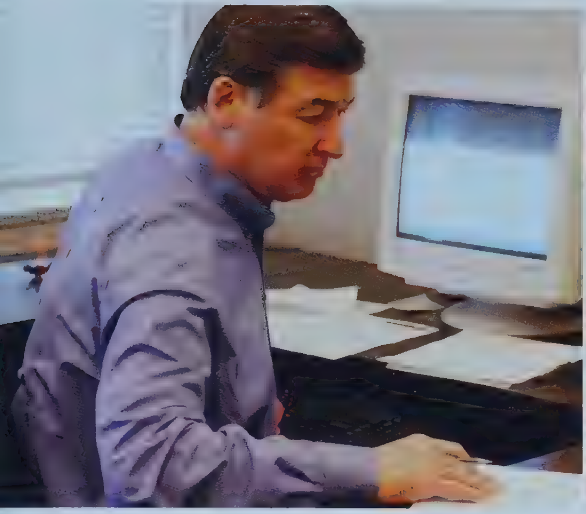
Based on an independent analysis of the potential CBM targets within the Western Canadian Sedimentary Basin, various prospective coal units have been identified and quantified. The greatest prospectivity occurs within the Upper Mannville, which is estimated to contain approximately 65% of the potential gas in place within the Alberta Plains. Several discrete areas have been targeted for land acquisition and subsequent evaluation. APF has focused its attention on an area approximately 113 kilometres northwest of Edmonton where three CBM project areas have been assembled. No reserves have been assigned for APF's Alberta CBM properties, as NI 51-101 requirements specify that reserves cannot be booked until commercial production levels are established.

Corbett Creek

Following the drilling, coring and testing of an initial exploratory well, four CBM wells and a water disposal well were drilled in late 2002 with water production commencing in the spring of 2003. Following nine months of de-watering an additional six wells were drilled and completed in early 2004 with production commencing in March. It is anticipated that by accelerating water production, the associated gas production will increase. Based on the calculated permeability of the coal it is estimated that de-watering will take a minimum of 12 months. Once commercial rates are achieved, full scale development is expected to commence. Each well costs approximately $600,000 to drill, case and complete. APF has an average 42% interest in over 10,000 acres at Corbett Creek with the potential to drill approximately 68 CBM wells.

Doris

At Doris, APF has assembled 22,400 gross acres of contiguous lands with interests between 35 and 50%. An initial exploratory test well was drilled in 2003 to evaluate the coals and encountered several conventional gas zones and was completed in those intervals and placed on production. A second well on this CBM prospect was also successful in finding conventional gas and was placed on production in early 2004. A third well has now been drilled and tested the Upper Mannville coals and has confirmed the potential for



Peter Klein

Elizabeth Palma

Violetta Piekarska

CBM, with an initial five well pilot project planned for late 2004. An existing CBM project is currently underway by another operator approximately three miles to the west where over 40 wells have been drilled, mostly in the last year. Extensive de-watering is in progress on that property, which APF believes will assist in the regional de-pressuring of the coals.

Timeu

An initial exploratory test well was drilled in the first quarter of 2004 and cored the Upper Mannville coal section. Following a thorough review of the data, a decision will be made regarding the drilling of a five well pilot project. APF has assembled over 5,700 acres of land on this project, and has a 100% working interest in the area.

Trochu-Rowley

APF has several active projects underway in this area located northeast of Calgary where over 60 CBM wells have been drilled by several companies. In this region, CBM development targets the Horseshoe Canyon coals. These coals are relatively thin and developed in up to ten individual seams with a total aggregate thickness of six to ten metres. These coals are also very shallow at depths of approximately 250 metres. These wells cost approximately $250,000 to drill, case and complete. One attribute of these coals is that there is no initial water production. APF is drilling, completing and immediately placing these CBM wells on production. Due to the extremely competitive nature of this development, the Trust has established several joint ventures in this area and hopes to expand its operations here over the next 12 months.

ENVIRONMENTAL ISSUES

In Alberta, all oil and gas operations are conducted under the rules and regulations of the Alberta government. All activities pertaining to the handling and disposal of produced CBM water are fully compliant with existing regulations from the Energy and Utilities Board and the Department of Energy. Produced CBM water is disposed into the subsurface in approved water disposal zones.

In Wyoming, the Wyoming Oil and Gas Conservation Commission, the Bureau of Land Management and the Department of Environmental Quality are responsible for regulation of the oil and gas industry. Produced CBM water is either disposed of in approved drainage areas or in applicable water containment reservoirs, with full consultation and approval of surface landowners.

APF is committed to ensuring that all its operations are conducted in an environmentally responsible manner, taking into consideration the sensitivity of surrounding areas and the impact on all stakeholders.

Oil and Natural Gas Reserves

All of APF's Canadian reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ"), while coalbed methane ("CBM") reserves in the United States were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"). Both reports were prepared effective January 1, 2004. All reserves were evaluated in accordance with the new standard, NI 51-101. No reserves were assigned to APF's Alberta CBM assets.

NI 51-101 replaced the former National Policy 2-B ("NP 2-B"). Under the new instrument, the total proved reserves are to reflect a 90% confidence level; that is, nine times out of ten, actual reserves recovered should exceed the estimated proved reserves. The proved plus probable reserves are to reflect a 50% or greater confidence level and are effectively meant to be the "best estimate" of the Company's reserves. This compares to the previous definition of "likelihood of existence" under NP 2-B. The following reserves summary has been prepared comparing the new proved plus probable reserves to previous proved plus risk adjusted (50%) probable reserves, which were commonly referenced as "established reserves" under NP 2-B.

The following table summarizes the Company Interest Reserves assigned in the GLJ and McDaniel reports. Company Interest Reserves are defined as working interest reserves (before the deduction of royalties) plus royalty interest reserves.

Summary of Reserves As at December 31, 2003	Natural Gas (mmcf)	Light & Medium Oil (mbbl)	Heavy Oil (mbbl)	NGL's (mbbl)	Total (mboe) (2)
Proved					
Developed producing	65,796	11,899	969	818	24,652
Developed non-producing	4,882	838	624	86	2,361
Undeveloped	2,016	2,269	201	75	2,880
Total Proved	72,695	15,006	1,793	979	29,894
Probable	26,503	4,629	1,210	172	10,428
Proved + Probable (1)	99,197	19,634	3,003	1,151	40,322

Columns may not add due to rounding

The reserves were evaluated using the GLJ January 1, 2004 price forecast. The net present values shown below do not necessarily represent the fair market value of the reserves.

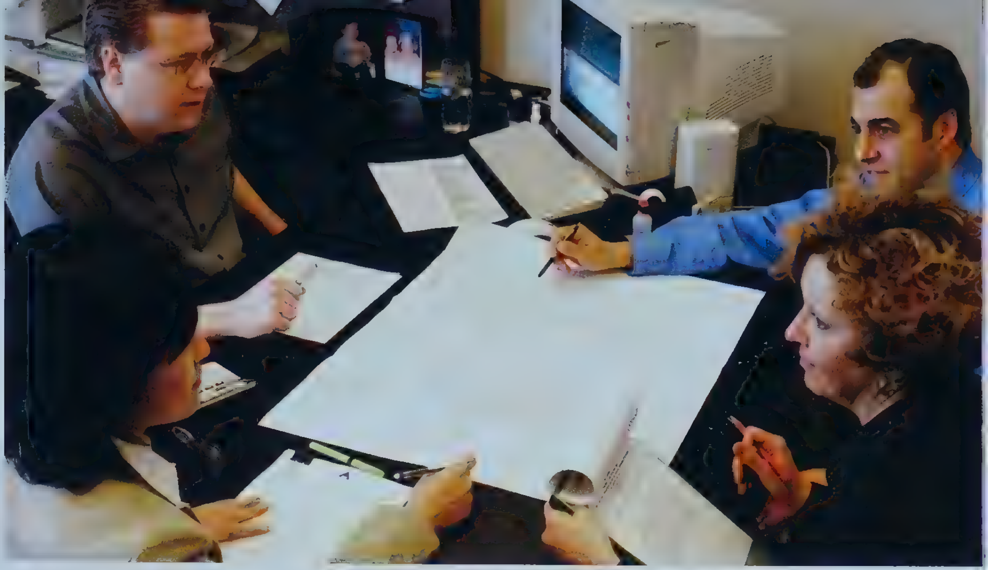
Net Present Value Of Future Net Revenue Before Income Taxes (Based on forecast pricing and costs)
As at December 31, 2003

	Present Value Discounted				
Reserve Category ($millions)	0%	8%	10%	12%	15%
Proved					
Developed producing	321.8	242.4	229.3	217.9	203.2
Developed non-producing	35.1	17.3	15.5	14.1	12.5
Undeveloped	31.7	14.6	12.2	10.3	8.0
Total Proved	388.6	274.3	257.0	242.3	223.7
Probable	123.8	66.8	59.4	53.4	46.0
Proved + Probable (1)	512.4	341.0	316.5	295.6	269.7

Columns may not add due to rounding

(1) Reserve numbers for 2002 and 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

(2) Boe's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.



Clockwise from top left: Murray Heather, Kevan Newman, Pat Forrest, Dilia Wu

GLJ Forecast at January 1, 2004 Year	Foreign Exchange ($U.S./$Cdn.)	WTI Oil ($U.S./bbl)	Heavy Oil ($Cdn./bbl)	Edmonton Light Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2004	0.75	29.00	20.25	37.75	5.85
2005	0.75	26.00	20.25	33.75	5.15
2006	0.75	25.00	21.00	32.50	5.00
2007	0.75	25.00	21.00	32.50	5.00
2008 - 2014	0.75	25.00	21.00	32.50	5.00
Escalate thereafter	–	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr

The following table contains a reconciliation of APF's proved plus probable reserves for the most recently completed calendar year. Additional information required under NI 51-101 will be included in the Annual Information Form to be filed for fiscal 2003 and will be available at www.sedar.com and www.apfenergy.com by the end of April.

Reconciliation of Proved Plus Probable Reserves

	Natural Gas (mmcf)		Light & Medium Oil (mbbl)		Heavy Oil (mbbl)		NGL's (mbbl)		Total (mboe)	
	Gross [1]	Net [2]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves at December 31, 2002 [3]	68,290	54,739	19,490	16,952	270	258	847	621	31,989	26,954
Extensions	2,375	1,943	390	327	–	–	7	5	793	656
Improved recovery	837	683	148	126	317	280	1	1	606	521
Technical revision	2,858	2,604	746	751	245	180	(10)	(27)	1,457	1,338
Discoveries	857	605	4	4	–	–	–	–	147	105
Acquisitions	36,659	30,424	2,982	2,648	2,579	2,374	437	300	12,107	10,393
Dispositions	(343)	(262)	(2,171)	(1,902)	–	–	–	–	(2,228)	(1,945)
Production	(12,336)	(9,748)	(1,955)	(1,643)	(407)	(347)	(131)	(95)	(4,549)	(3,710)
Reserves at December 31, 2003	99,197	80,988	19,634	17,263	3,003	2,745	1,151	805	40,322	34,311

Columns may not add due to rounding

(1) Gross reserves for the purposes of this analysis are defined as total Company Interest Reserves. "Company Interest Reserves" are defined as working interest reserves (before the deduction of royalties) plus royalty interest reserves.

(2) Net reserves for the purpoes of this analysis are defined as net after royalty reserves.

(3) Reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties for 2002 and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

Corporate Development

In 2003 APF completed three corporate and several asset acquisitions for a total value of approximately $167 million, making it the most prolific period of growth in APF's seven-year history.

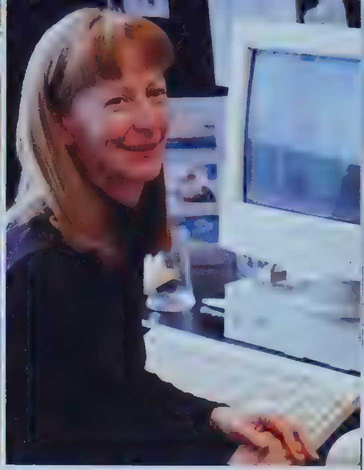
APF evaluates assets based on two criteria: the buying opportunity and the upside potential. The Trust's Corporate Development team is comprised of individuals with expertise in geology, engineering, land management and finance. In 2003, the Trust completed corporate and asset transactions worth approximately $167 million, making it the most prolific period of growth in APF's seven-year history. Over the course of the year, APF evaluated almost $5 billion in potential acquisitions before executing on those offering the best buying opportunities and upside potential.

The bulk of the 2003 activity was reflected in three corporate transactions, which increased the Trust's gas weighting to approximately 45% of the asset mix, and gained access to long-life CBM properties in Alberta and Wyoming. The Trust continued to consolidate its interest in a number of core areas, acquiring production at Countess, Queensdale and Vermilion throughout the year. A portfolio review of APF's properties resulted in the divestiture of approximately 533 boe/d of non-core assets and the farm-out of higher risk exploration lands. APF will continue to search for new opportunities that add value to an already strong asset base.

ACQUISITION OF HAWK OIL INC.

On February 5, 2003, APF acquired Hawk Oil Inc., a Calgary-based gas levered producer for a total cost of $49.1 million. At the time of the acquisition, Hawk's production was 2,700 boe/d consisting of 9.3 mmcf/d of gas (61%) and 1,150 bbls/d of oil (39%). Assets acquired in this transaction served to further increase APF's presence in Central Alberta. In addition, Hawk had a heavy oil portfolio that offered diversity to APF's existing asset base. In the aggregate, the assets had an average 98% working interest and included natural gas interests at Paddle River, Vermilion and Holmberg, along with heavy oil in the Lloydminster and Epping areas. The transaction included approximately 37,000 net acres of undeveloped land and an extensive proprietary seismic database.

Heather Rampersaud



Pat Morris

ACQUISITION OF NYCAN ENERGY CORP.

On April 23, 2003, APF acquired approximately 1,265 boe/d through the purchase of Nycan Energy Corp. for $42.4 million. Daily volumes were comprised of 5,700 mcf/d of gas (77%) and 315 bbls/d of oil and natural gas liquids (23%) of which 65% was operated. The acquisition complemented APF's existing asset base in Southeast Alberta and further increased the Trust's gas weighting. The major assets included interests at Carmangay, Enchant, Little Bow, Long Coulee, Retlaw and Turin. The acquisition also included approximately 58,000 net undeveloped acres of land.

ACQUISITION OF CANSCOT RESOURCES LTD.

On September 26, 2003, APF acquired CanScot Resources Ltd., a coalbed methane ("CBM") producer with operations in both Canada and the Unites States, for a total consideration of $42.1 million. Conventional production at the time of purchase was approximately 800 boe/d, consisting of 3,900 mcf/d of gas (81%) and 150 bbls/d of oil. The transaction comprised a focused group of high working interest long-life conventional and CBM properties in Alberta and Wyoming and included approximately 45,800 net acres of undeveloped land. Key CanScot staff joined APF, bringing with them extensive CBM experience in both Canada and the United States.

[illegible]: Kellie D'Hondt, Chris Palacz

[illegible]

[illegible] 29, 2003 APF acquired incremental production of [illegible]'d and deep hole rights at Countess, its largest gas [illegible]ty, in Southeast Alberta, for $7.03 million. The aver[illegible]rking interest was 73%. In addition to the long-life [illegible]n, the acquisition provided the Trust with several [illegible]ment prospects in the deeper Mannville and Basal [illegible] formations.

[illegible] July 30, 2003, APF acquired a 2.55% interest in the [illegible] Unit No. 1, which added approximately 380 boe/d [illegible]uction (89% light oil). APF initially signed a purchase and sale agreement with the vendor, for 17% of the Unit for $91.8 million, that was subject to certain rights of first refusal ("ROFR") by another party. The party exercised the ROFR, which resulted in APF receiving a small interest of the Unit for approximately $15.9 million. The Swan Hills assets are characterized by long-life, low-decline production and high quality, light gravity oil (41 degree API). The operator, a senior oil and gas producer, is continuing to develop the reservoir through reef and edge/infill drilling and miscible flood exploitation.

Land Holdings

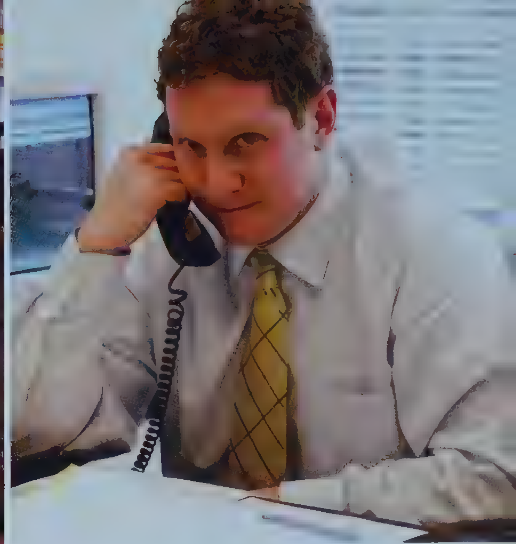
	Developed Land		Undeveloped Land		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	450,251	204,878	422,156	236,039	872,407	440,917
BC	1,979	387	–	–	1,979	387
Manitoba	161	27	966	412	1,127	439
Saskatchewan	62,247	30,262	156,524	77,172	218,771	107,434
Wyoming	4,754	1,047	20,696	7,812	25,450	8,859
Total	519,392	236,601	600,342	321,435	1,119,734	558,036

In addition to the oil and gas reserves, GLJ also valued APF's 321,435 acres of net undeveloped land, at $19.1 million. The value was derived by reference to land sales proximate to APF's undeveloped acreage, the applicable working interest and expiry profile.

Corporate Review

Business Objectives

Christine Ezinga



Jesse Meidl

The goal of APF Energy Trust is to provide unitholders with stable cash distributions and strong total returns. To achieve this, the Trust must continually replace production with new reserves, either through internal drilling and optimization initiatives or through accretive acquisitions.

In order to replace these reserves and achieve growth, APF must be able to successfully identify development prospects and evaluate acquisition opportunities. The Trust has demonstrated an ability, throughout its history, to complete acquisitions at favourable metrics, resulting in high and stable cash distributions for unitholders. APF will continue to utilize its internal expertise to optimize its inventory of undeveloped land and to assess potential acquisitions.

EQUITY ISSUES

APF completed its initial public offering for $35 million on December 16,1996. Since then, the Trust has issued an additional 33.9 million units, raising approximately $345 million in equity to fund growth and development initiatives. APF will continue to issue equity from time to time, to finance acquisitions and capital budget requirements.

Type	Date	Unit Price ($)	Units (000)	Gross Proceeds ($000)
IPO	Dec-96	10.00	3,500	35,000
New issue	Dec-98	8.00	2,260	18,080
New issue	Mar-00	7.30	1,223	8,928
New issue	Mar-01	10.00	3,301	33,010
Acquisition	Apr-01	10.05	902	9,061
New issue	Jun-01	11.50	3,050	35,075
Private placement	Oct-01	9.55	1,080	10,314
New issue	Feb-02	9.75	3,250	31,688
Acquisition	May-02	10.15	3,385	34,358
Acquisition	Feb-03	9.45	3,990	37,708
New issue	Apr-03	10.40	5,352	55,670
Acquisition	Sep-03	11.50	1,342	15,433
New issue	Feb-04	11.60	4,765	55,300
Total			37,400	379,625

Left to right: Alan MacDonald, VP Finance; Steve Cloutier, President

DISTRIBUTIONS

Cash distributions are paid monthly to unitholders of record on the applicable record date. APF's record date is the last trading day of the month. In order to be a unitholder on the record date, units must have been purchased prior to the ex-distribution date, which is two trading days earlier. Key dates for 2004 are set out in this annual report. Purchases of units which settle on or after the ex-distribution date are not eligible for that month's distribution, but will qualify for the next month's distribution. Payments are made to unitholders on the 15th of the following month (if the 15th day of the month falls on a holiday or weekend, the distribution is paid the next business day). Since inception, the Trust has distributed $13.83 per unit to December, 2003, or an average of $1.98 per year.

DISTRIBUTION REINVESTMENT PLAN

On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003. The DRIP allows eligible Unitholders to reinvest their proceeds in additional Trust units at a price equal to 95% of the volume-weighted average price over a certain period, or receive a cash payment equal to 102% of the regular distribution.

Historical Distributions

Distribution Date ($)	**2003**	2002	2001	2000	1999	1998	1997
January 15th	**0.160**	0.150	0.220	0.125	0.120	0.475	0.210
February 15th	**0.160**	0.150	0.250	0.125	0.160	–	–
March 15th	**0.165**	0.150	0.250	0.125	0.120	0.120	–
April 15th	**0.185**	0.150	0.225	0.125	0.120	0.120	0.455
May 15th	**0.185**	0.150	0.300	0.125	0.160	0.175	–
June 15th	**0.200**	0.150	0.300	0.135	0.120	0.120	–
July 15th	**0.200**	0.150	0.300	0.135	0.120	0.120	0.420
August 15th	**0.200**	0.150	0.300	0.135	0.135	0.175	–
September 15th	**0.200**	0.150	0.250	0.140	0.125	0.120	–
October 15th	**0.175**	0.150	0.250	0.210	0.125	0.120	0.425
November 15th	**0.175**	0.150	0.200	0.210	0.125	0.175	–
December 15th	**0.175**	0.150	0.200	0.310	0.125	0.120	–
Total	**2.180**	1.800	3.045	1.900	1.555	1.840	1.510
Cumulative Total	**13.830**	11.650	9.850	6.805	4.905	3.350	1.510

Key 2004 Distribution Dates

JANUARY

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	**15**	16	17
18	19	20	21	22	23	24
25	26	27	**28**	29	**30**	31

FEBRUARY

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22	23	24	**25**	26	**27**	28
29						

MARCH

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28	**29**	30	**31**			

APRIL

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MAY

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23/30	24/31	25	26	**27**	28	29

JUNE

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27	**28**	29	**30**			

JULY

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11	12	13	14	**15**	16	17
18	19	20	21	22	23	24
25	26	27	**28**	29	**30**	31

AUGUST

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22	23	24	25	26	**27**	28
29	30	**31**				

SEPTEMBER

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26	27	**28**	29	**30**		

OCTOBER

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17	18	19	20	21	22	23
24/31	25	26	**27**	28	**29**	30

NOVEMBER

S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	**15**	16	17	18	19	20
21	22	23	24	25	**26**	27
28	29	**30**				

DECEMBER

S	M	T	W	T	F	S
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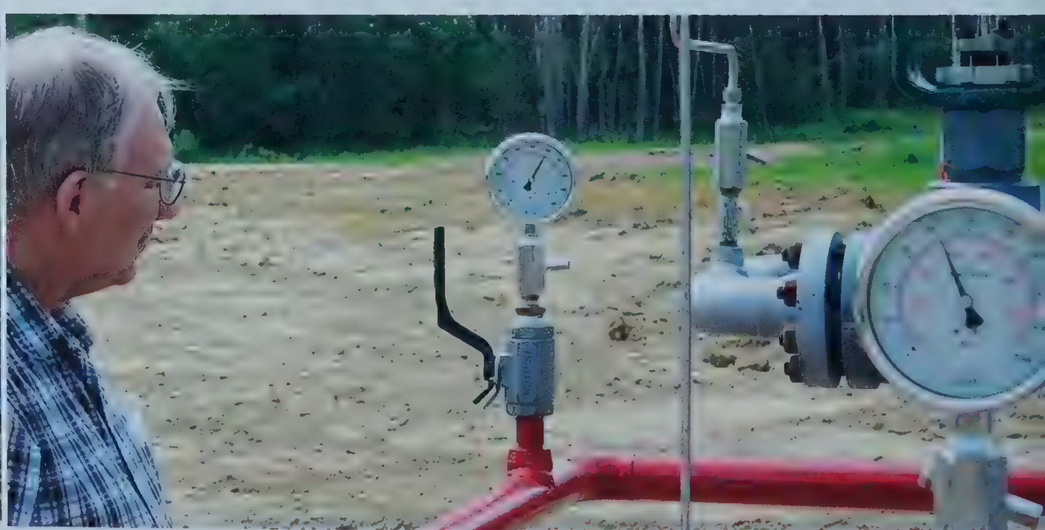
12	13	14	**15**	16	17	18
19	20	21	22	23	24	25
26	27	28	**29**	30	**31**	

Distribution Date **Ex-Distribution Date** **Record Date**



Bob Wilshusen

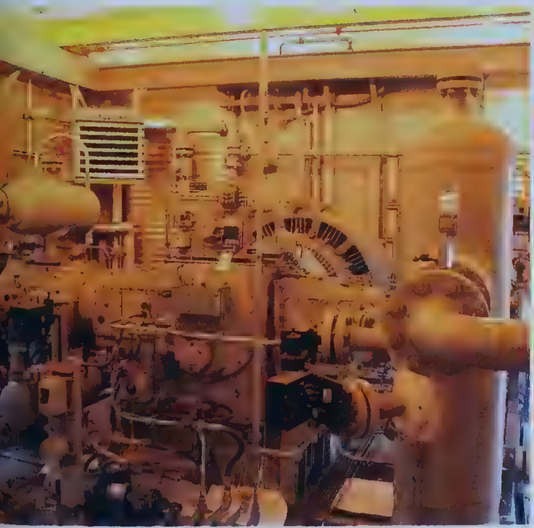
Taxation

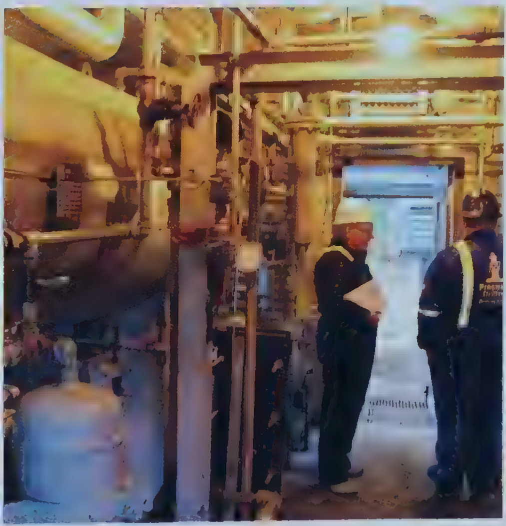
Distributions have two components for taxation purposes: the taxable portion, which is a return on capital; and the tax deferred return of capital, which reduces the unitholder's adjusted cost base each time a distribution is paid out. APF provides a summary to unitholders, on an annual basis, illustrating what portion is taxable and what portion is a return of capital. The following table summarizes the breakdown of distributions paid by the trust since inception.

	Total Distributions	Income		Return of Capital	
	($)	($)	(%)	($)	(%)
2003	**2.18**	**1.72**	**78.81**	**0.46**	**21.19**
2002	1.80	1.14	63.52	0.66	36.48
2001	3.05	1.74	57.18	1.30	42.83
2000	1.90	1.18	62.14	0.72	37.86
1999	1.55	0.53	33.83	1.03	66.17
1998	1.84	0.45	24.63	1.39	75.38
1997	1.51	0.60	39.54	0.91	60.46
Total	13.83	7.36		6.47	

Distributions paid by the Trust to non-corporate unitholders who are U.S. residents or citizens are to be treated as "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003, and are generally eligible for the reduced U.S. dividend tax rate.

On March 23, 2004, the federal budget proposed that the tax treatment of distributions to non-residents be changed so that the deemed capital portion of distributions to non-residents will now be taxed at a rate of 25% (reduced to 15% for U.S. residents). From a practical perspective this will not impact APF as our Trustee has historically always applied the withholding tax on the full amount of our distributions, and not just the income portion.





Corporate Governance

APF is committed to ensuring that its governance structure provides unitholders with the highest degree of confidence that the Trust's business and operations are being conducted with the unitholders' interests in mind.

The relationship between the Board and management of APF is built around the mutual understanding of their respective [illegible] and the ability of the Board to act independently in [illegible]ying out its responsibilities. The Board's participation in [illegible]tegic planning recognizes that the role of directors is not [illegible]nage on a day-to-day basis, but to provide stewardship [illegible]agement in executing the overall business strategies [illegible]. The Board oversees and monitors the management [illegible] and regularly reviews the status of the business plan [illegible]nent.

[illegible] directors are elected by unitholders. Voting for [illegible] is conducted during APF's annual general meet-[illegible] APF Board is comprised of individuals who have a [illegible] of experience and business knowledge, and has [illegible]ed in size to accommodate the growth and complex-[illegible] Trust. In keeping with best practices, the roles of [illegible]irman and Chief Executive Officer are separate.

[illegible] Board meets regularly to discuss the Trust's opera-[illegible] business. When circumstances warrant, additional [illegible]gs are scheduled to deal with time-sensitive or special [illegible]ons. Excluding special meetings and monthly meet-[illegible] to set the cash distribution, the Board meets quarterly [illegible]th management to review major operational and financial [illegible]spects of APF. Also, the unrelated directors meet indepen-[illegible]ntly of the related directors when circumstances warrant.

Governance is the responsibility of the full Board. The Board is tasked with reviewing its size and composition and that of its committees. The Board has open access to the Trust's legal advisors at all times and may retain independent counsel if circumstances warrant.

INDEPENDENCE OF THE BOARD

The Board is currently comprised of six members. Four of the six are unrelated directors and the remaining two are represented by APF's Chief Executive Officer and the President. The Board ensures that APF discloses on an annual basis the number of related and unrelated directors.

COMMITTEES

The Board has three committees: Audit, Reserves and Compensation. The committees have formal written mandates that are reviewed annually, taking into account changes in regulatory requirements or practices. Changes are proposed to the Board as deemed necessary.

Audit Committee

The Audit Committee is comprised of all the unrelated Directors. All committee members possess the requisite financial skills to qualify them as members. The Audit Committee meets at least quarterly with management and the external auditors to review the quarterly and annual financial statements and also meets independently with the auditors at least twice annually.

Reserves Committee

The Reserves Committee is comprised of all the unrelated Directors. The Reserves Committee oversees the integrity of APF's reserve estimates and carries out its duties in accordance with NI 51-101. The Committee meets at least twice per year with management and the independent engineering consultants. The Committee is also responsible for overseeing those procedures and policies that minimize environmental, occupational safety and health risk, as APF dedicates itself to achieving the highest standards of performance.

Compensation Committee

The Compensation Committee is comprised of two unrelated Directors and the President. The committee is responsible to the Board for overseeing the development of competitive compensation policies designed to attract, develop and retain employees of the highest standards at all levels. It is responsible for recommending to the Board the compensation arrangements for senior officers and oversees the administration of succession planning. The committee reviews Directors' compensation and makes recommendations as deemed necessary.

In conjunction with proposed corporate governance standards, the President of APF will resign from the committee and all members will be unrelated following the Annual General Meeting.

APF is committed to protecting the health and safety of all individuals affected by our activities. Through the office of the Environment, Health and Safety Coordinator, execution of our policies ensures that the Trust safeguards the environment and contributes to the well-being of the communities in which we live and operate.

ENVIRONMENT

APF continues to promote guidelines, standards and procedures that support our environmental policy. This commitment is demonstrated by setting objectives to actively foster continual improvement. APF meets or exceeds all applicable government regulations and industry codes of practice relating to environmental protection, and works with those organizations in the furtherance and development of appropriate policies.

In 2003, APF became a member of the Environment, Health and Stewardship program initiated by the Canadian Association of Petroleum Producers. Participation in this program demonstrates a commitment to industry and corporate excellence in environmental, health and safety performance and will facilitate communication to all stakeholders.

The Trust implemented a comprehensive auditing program to ensure that environmental liabilities are identified and corrected. An environmental inventory management system has been established, allocating funds on an annual basis, to actively manage any potential for liabilities.

HEALTH AND SAFETY

APF has established measurable performance targets relating to the health and safety of employees and contractors. Regular meetings and training programs are conducted to review and discuss health and safety regulations and workplace practices and procedures so that all employees and contractors have the skills necessary to attain these goals. Occupational health and safety is systematically managed and integrated into all business decisions, plans and operations, maintaining compliance with applicable laws, regulations and policies.

Emergency response plans and procedures are continually assessed to ensure APF can react effectively and efficiently to incidents, thus minimizing any possible impact. Simulation events are conducted on a regular basis so emergency response plans remain current and appropriate.

APF promotes consultation with the public, government agencies and other stakeholders regarding the Trust's operations and is responsive to their concerns. Third party and internal audits of APF operations are conducted to identify risks and initiate proactive steps to reduce or prevent exposure.

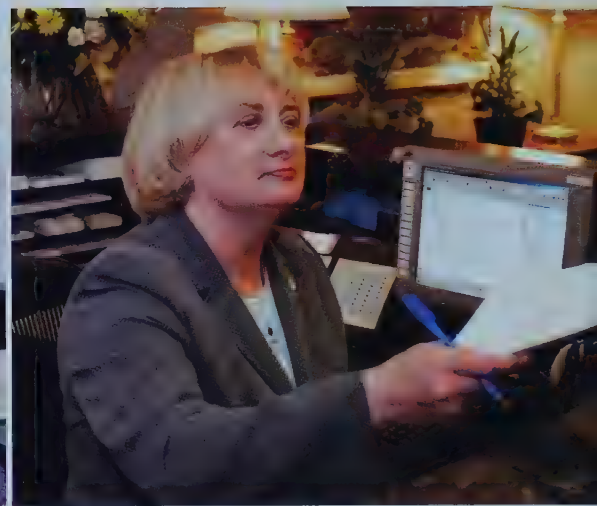
Environment, health and safety aspects and the impact of all proposed activities are assessed on an ongoing basis so appropriate hazard control measures can be designed and implemented. Excellence is achieved through the support and active participation of all management, employees and contractors working for APF. Our policy is reviewed annually and modified as appropriate.

Members of the APF Team hike to the Burgess Shale, a world renowned geological location in British Columbia.

Corporate Social Responsibility

[illegible]

Jason Thompson



Margaret Gilchrist

APF is committed to fostering ongoing positive relationships between our business and stakeholders through the implementation of a Corporate Social Responsibility ("CSR") program. The socio-economic well-being of our communities and those who work and live in them is directly linked to the success of APF.

OUR EMPLOYEES

APF is continually striving to be an employer of choice, recognizing the value of work-life balance for employees. Corporate fitness facilities and active interaction on a social level result in a more productive and engaged group of professionals. Ongoing opportunities for continuing education are provided and employees are encouraged to participate in the decision-making process of the business.

OUR BUSINESS PARTNERS AND COMMUNITIES

APF seeks out business partners with similar values. These entities must not engage in activity that would harm the environment or compromise surrounding communities. Any such activity has the potential of putting APF and its reputation at risk.

APF's Environment, Health and Safety program forms an integral part of the Trust's CSR initiative. The Trust's Environment, Health and Safety Co-ordinator and Manager of Surface Land and Community Affairs work closely with those most affected by APF's field operations to ensure that we are the best possible partner in the community.

Currently, APF invests in the future of our communities through gifts to charities and service clubs and the sponsorship of events. Many of our employees volunteer time to a diverse range of organizations sharing with them their skills and passions.

In 2003, APF contributed to a wide-ranging field of charities and service clubs including: Alberta Cancer Foundation, Inn from the Cold Society, R. B. Bennett Elementary School in Calgary, and a host of minor league sporting teams across Alberta and Saskatchewan.

INVESTORS

APF's unitholders expect their interests in oil and gas assets to be managed in an effective and efficient manner, with a view to balancing the economic value of their investment with the interests of the community. Through APF's CSR plan, unitholders have ongoing disclosure of the Trust's performance and goals, making it easier for them to evaluate APF from a more dynamic perspective.

Management's Discussion and Analysis

The following discussion should be read in conjunction with the audited consolidated financial statements included in this annual report. The financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars. Additional information relating to APF, including disclosures required under National Instrument 51-101, can be found in APF's Annual Information Form ("AIF") on SEDAR at www.sedar.com or on APF's website at www.apfenergy.com.

PRODUCTION

During the fourth quarter, production increased by 38% over the same period in 2002. Production volumes for the year were 46% higher in 2003, due primarily to the acquisitions of Hawk Oil Inc. ("Hawk"), Nycan Energy Corp. ("Nycan") and CanScot Resources Ltd. ("CanScot"). Natural production declines were partially offset throughout the year by production increases from successful development drilling programs at Queensdale, Macoun and Tatagwa in Southeast Saskatchewan and at Countess in Southeast Alberta. A $40 million capital expenditure budget has been set forth in 2004 and is expected to maintain production levels at the 2003 exit rate of approximately 13,000 boe/d.

	Three Months Ended December 31			Year Ended December 31		
	2003	2002	% Change	**2003**	2002	% Change
Crude oil (bbl/d)	**6,499**	6,001	8	**6,472**	5,307	22
Natural gas (mcf/d)	**36,929**	19,776	87	**33,799**	18,488	83
NGL (bbl/d)	**474**	187	153	**358**	144	149
Total (boe/d) (1)	**13,128**	9,484	38	**12,463**	8,532	46
Production split						
Oil & NGLs	**53%**	65%		**55%**	64%	
Natural gas	**47%**	35%		**45%**	36%	

(1) Boe's may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a boe conversion ratio for natural gas of 6 mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

MARKETING

In 2003, APF's production mix was 55% crude oil and NGL's and 45% natural gas. Crude oil was sold under 30-day evergreen contracts while approximately 25% of natural gas production was sold to aggregators pursuant to long-term contracts, with the remaining 75% sold on the spot market.

PRICES

During the fourth quarter of 2003, price realizations declined a modest 3% for the same quarter in 2002, due largely to a 16% decrease in the value of the U.S. dollar against the Canadian dollar. Oil pricing was most affected by the change in currency exchange rates, with price realizations decreasing by 12% while the benchmark West Texas Intermediate ("WTI") pricing increased 11% over the fourth quarter of 2002. Natural gas pricing during the quarter increased by 14% over the same period in 2002.

WTI oil prices averaged $U.S. 31.06 per bbl in 2003, 19% higher than the 2002 average of $U.S. 26.10. Crude oil prices in Canada are based on the WTI reference price, adjusted for transportation, differentials and foreign exchange. The price received by APF is based upon the refiners' posted price, less transportation and adjustments for APF's product quality relative to the posted price and adjusted for hedging. APF's oil price after hedging averaged $34.46 per bbl in 2003, compared with $33.66 per bbl in 2002, an increase of 2%.

Canadian oil prices were negatively impacted by an average 11% decrease in the value of the U.S. dollar versus the Canadian dollar during 2003. The NYMEX futures contracts for the remainder of 2004 suggest crude oil prices will exceed 2003 levels during the year.

APF's realized natural gas price after hedging for the year averaged $6.32 per mcf, 65% higher than the average realized price of $3.83 per mcf in 2002. This is consistent with the increase in the benchmark AECO price in Alberta, which increased by an average of 63% from 2002 levels. APF expects gas prices during 2004 to remain consistent with or exceed 2003 levels as supply concerns dominate the market.

	Three Months Ended December 31			Year Ended December 31		
Prices - After Hedging	**2003**	2002	% Change	**2003**	2002	% Change
Crude oil ($Cdn./bbl)	**$ 31.66**	$ 35.80	(12)	**$ 34.46**	$ 33.66	2
Natural gas ($Cdn./mcf)	**5.41**	4.74	14	**6.32**	3.83	65
NGL ($Cdn./bbl)	**31.37**	30.63	2	**31.82**	25.15	27
Total ($Cdn./boe)	**$ 32.03**	$ 33.14	(3)	**$ 35.95**	$ 29.65	21
Reference Pricing						
WTI ($U.S./bbl)	**$ 31.18**	$ 28.14	11	**$ 31.06**	$ 26.10	19
AECO gas ($Cdn./mcf)	**$ 5.59**	$ 5.25	6	**$ 6.67**	$ 4.08	63
Foreign exchange ($U.S./$Cdn.)	**$ 1.3157**	$ 1.5695	(16)	**$ 1.4010**	$ 1.5703	(11)

HEDGING

Commodity prices are susceptible to market fluctuations. APF actively manages commodity price risk by entering into hedging contracts to protect revenues from fluctuations in commodity prices. Hedging is intended to provide stability to cash distribution levels by fixing the price of commodities on a portion of the production portfolio. One of the key assumptions in the preparation of APF's annual budget and estimate of annual distributions is commodity price. APF's mandate is to ensure that a portion of the year's distributions, based on certain commodity price assumptions, are protected. APF looks for opportunities to sell forward a portion of its production at levels at, or better than, the commodity prices used in the budget process. While this guideline necessarily implies that commodity prices may rise, it must be acknowledged that commodity prices may fall. In this regard, in situations where commodity prices are below those used in the annual budget, management's expertise is relied upon to ensure that potential opportunities to mitigate the impact of lower commodity prices are executed. Hedging activities during 2003 reduced revenues by $3.56 million, reducing the realized oil price by $1.61 per bbl and increasing the natural gas price by $0.02 per mcf. At the time of printing APF had the following hedges in place:

Current Hedging Position

Period	Type of Commodity	Average Contract	Average Daily Quantity	Hedged Price
March 2004	Crude oil	Swap	3,000 bbls	$U.S. 30.76/bbl
March 2004	Natural gas	Swap	10,000 GJ	$Cdn. 7.19/GJ
March 2004	Natural gas	Physical	2,000 mmbtu	$U.S. 7.00/mmbtu
April to June 2004	Crude oil	Swap	2,500 bbls	$U.S. 30.78/bbl
April to June 2004	Natural gas	Swap	10,333 GJ	$Cdn. 5.76/GJ
April to June 2004	Natural gas	Swap	1,000 mmbtu	$U.S. 5.19/mmbtu
July to September 2004	Crude oil	Swap	2,167 bbls	$U.S. 29.58/bbl
July to September 2004	Natural gas	Swap	10,000 GJ	$Cdn. 5.75/GJ
July to September 2004	Natural gas	Swap	1,000 mmbtu	$U.S. 5.19/mmbtu
October to December 2004	Crude oil	Swap	1,833 bbls	$U.S. 30.45/bbl
October to December 2004	Natural gas	Swap	3,333 GJ	$Cdn. 5.75/GJ
October to December 2004	Natural gas	Swap	333 mmbtu	$U.S. 5.19/mmbtu
January 2005	Crude oil	Swap	1,000 bbls	$U.S. 31.74/bbl

In addition to commodity hedging, APF has also entered into foreign currency hedge contracts in order to mitigate currency risk. The Trust has hedged $U.S. 20 million of revenue at a rate of $Cdn. 1.3317 or $U.S. 0.7509 for calendar 2004.

At December 31, 2003, APF had fixed the interest rate on a portion of its debt as follows:

Term	Amount (000)	Interest Rate
January 2004 to February 2005	$ 20,000	3.67% plus stamping fee
January 2004 to May 2005	$ 20,000	3.75% plus stamping fee
January 2004 to November 2005	$ 20,000	3.58% plus stamping fee

REVENUES

Revenues for the fourth quarter of 2003, net of hedging, increased to $39 million from $29 million during the fourth quarter of 2002. Increased revenues from natural gas contributed to 46% of total revenue in the fourth quarter of 2003, an increase of $9.2 million over the same period in the previous year.

Annual revenues, net of hedging transactions increased 76% to $165 million in 2003, due to a combination of higher production volumes and higher commodity prices.

	Three Months Ended December 31				Year Ended December 31			
Oil and Gas (000 except per boe amounts)	**2003**	**% of Total**	2002	% of Total	**2003**	**% of Total**	2002	% of Total
Crude oil sales	**$ 19,536**	**50**	$ 20,948	71	**$ 85,193**	**51**	$ 69,390	74
Natural gas sales	**17,830**	**46**	8,624	29	**77,747**	**47**	25,534	27
NGL sales	**1,367**	**3**	527	2	**4,157**	**3**	1,320	1
Hedging	**(44)**	**–**	(1,180)	(4)	**(3,565)**	**(2)**	(3,899)	(4)
Other	**421**	**1**	461	2	**1,925**	**1**	1,676	2
Total revenue	**39,110**	**100**	29,380	100	**165,457**	**100**	94,021	100
Per boe	**$ 32.38**		$ 33.67		**$ 36.37**		$ 30.19	

ROYALTIES

For the fourth quarter, royalties as a percentage of revenue were 5% higher in 2003, as a result of higher commodity pricing. Royalties per barrel of oil equivalent produced were 19% higher in 2003, consistent with the increase in commodity prices during the year. Royalties as a percentage of revenues were essentially unchanged.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Crown royalties	**$ 4,838**	$ 2,862	69	**$ 19,364**	$ 10,905	78
Freehold royalties	**2,120**	2,310	(8)	**10,193**	6,323	61
Overriding royalties	**609**	265	130	**2,916**	1,479	97
Total royalties	**$ 7,567**	$ 5,437	39	**$ 32,473**	$ 18,707	74
% of revenue after hedging	**19.3%**	18.5%	5	**19.6%**	19.9%	(1)
Per boe	**$ 6.26**	$ 6.23	–	**$ 7.14**	$ 6.01	19

OPERATING COSTS

Fourth quarter operating costs increased by 16% over the same period in 2002, while annual costs increased by 12% in 2003 to average $7.12 per boe. Increases were primarily due to initial field optimization costs on newly acquired properties and higher energy costs. Continued high energy costs and general higher field costs associated with APF's current property portfolio are expected to negate any operating efficiencies initiated to reduce operating costs in 2004.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Operating costs	**$ 9,619**	$ 5,970	61	**$ 32,370**	$ 19,748	64
Per boe	**$ 7.97**	$ 6.84	16	**$ 7.12**	$ 6.35	12

NETBACKS

Netbacks decreased from $20.60 per boe in the fourth quarter of 2002 to $18.15 per boe during the fourth quarter of 2003, resulting from lower revenues which were negatively impacted by currency exchange rates and a 16% increase in operating costs. Higher commodity prices during 2003 offset increased royalty expenses and operating costs during 2003, resulting in annual operating netbacks of $22.11/boe, a 24% increase from 2002.

	Three Months Ended December 31			Year Ended December 31		
($ per boe)	**2003**	2002	% Change	**2003**	2002	% Change
Net revenue (after hedging)	**$ 32.38**	$ 33.67	(4)	**$ 36.37**	$ 30.19	20
Royalties	**(6.26)**	(6.23)	–	**(7.14)**	(6.01)	19
Operating costs	**(7.97)**	(6.84)	16	**(7.12)**	(6.35)	12
Netback	**$ 18.15**	$ 20.60	(12)	**$ 22.11**	$ 17.83	24

GENERAL AND ADMINISTRATIVE

General and administrative costs increased in absolute terms for both the quarterly and annual periods of 2003, by 157% and 116% respectively, compared with 2002. The increase is due primarily to costs associated with the increase in staffing levels from recent corporate and property acquisitions and the cost of APF's short-term incentive plan ("STIP"), which was introduced for 2003 following the termination of the management contract.

The STIP was created to encourage and reward outstanding employee performance and to ensure that the interests of both the unitholders and employees were aligned. The STIP enables all eligible employees to participate in a bonus pool, provided APF generates at least a 10% total annual return. Total annual return is calculated as distributions paid during the year plus or minus the change in unit price compared with the previous year-end. When the 10% total return threshold is met, a portion of net operating income ("NOI") is allocated to the bonus pool and shared by all eligible employees. The total return on APF units for the year ended December 31, 2003 was 50%. Based on this total return, the bonus pool under the STIP for the year was $3.35 million (2002 - $nil). Senior employees, including officers, may also be eligible to receive performance bonuses based on criteria applicable to each individual's responsibilities. Excluding the STIP, general and administrative costs per boe for the year ended December 31, 2003 were $1.47.

APF's success at finding and developing oil and gas reserves is due to its ability to recruit highly competent individuals with strong technical skill sets. Accordingly, APF's compensation structure is designed to provide employees with a competitive base package and the potential to enhance the base, provided unitholders experience strong returns.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
General and administrative	**$ 3,980**	$ 1,547	157	**$ 10,023**	$ 4,635	116
Per boe	**$ 3.30**	$ 1.77	86	**$ 2.20**	$ 1.49	48

MANAGEMENT FEE

Prior to the internalization of the management contract, the Manager received a management fee equal to 3.5% of net production revenue. During 2002, management fees amounted to $1.98 million ($0.63 per boe) compared with $0.65 million ($0.75 per boe) for the fourth quarter 2002. Commencing January 1, 2003, no management fees were payable.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Management fee	**$ –**	$ 654	(100)	**$ –**	$ 1,976	(100)
Per boe	**$ –**	$ 0.75	(100)	**$ –**	$ 0.63	(100)

INTEREST

Interest expense increased 27% and 47% for the fourth quarter and year ended 2003 respectively. The increases were due to higher average debt levels arising from the various corporate and property acquisitions completed during 2003. At December 31, 2003, APF had fixed the interest rate on $60 million of debt (2002 - $30 million) at an average rate of 3.67% (2002 - 3.76%) plus applicable stamping fee, maturing in 2005.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Interest	**$ 1,087**	$ 854	27	**$ 4,171**	$ 2,834	47
Per boe	**$ 0.90**	$ 0.98	(8)	**$ 0.92**	$ 0.91	1

DEPLETION, DEPRECIATION AND AMORTIZATION

Depletion, depreciation and amortization ("DD&A") increased by 68% per boe in the fourth quarter of 2003 from the same period in 2002 and 14% for the year to $13.90 and $11.08 per boe respectively. The increases reflect the current year's acquisitions being higher than the historical average cost per boe.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Depletion and amortization	**$ 16,791**	$ 7,226	132	**$ 50,417**	$ 30,200	67
Per boe	**$ 13.90**	$ 8.28	68	**$ 11.08**	$ 9.70	14

SITE RESTORATION

Site restoration increased by 4% per boe during the fourth quarter from the same period in 2002 and by 9% to $0.73 per boe for the year, reflecting the future incremental site reclamation costs associated with acquisitions completed during 2003.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Site restoration	**$ 827**	$ 576	44	**$ 3,327**	$ 2,087	59
Per boe	**$ 0.69**	$ 0.66	4	**$ 0.73**	$ 0.67	9

COMPENSATION EXPENSE

During 2003, as part of APF's long-term incentive plan, 1,538,250 Trust unit incentive rights (2002 – 441,233) were issued to employees and directors, at prices ranging from $9.67 to $11.54 per Trust unit (2002 - $9.73 to $10.80). The exercise price of the rights is adjusted downward over time by the amount, if any, that quarterly distributions exceed 2.5 % of the net book value of property, plant and

equipment. The rights have a 10-year term and vest in one-third increments on the first, second and third anniversaries of their grant. Rights to purchase 1,824,330 Trust units at an average adjusted exercise price of $9.09 were outstanding at December 31, 2003. These rights have an average remaining contractual life of 9.3 years and expire at various dates to September, 2013. There were 47,221 rights exercisable at December 31, 2003 (2002 – nil).

APF has prospectively adopted the CICA Handbook Section 3870 – "Stock Based Compensation". Under the transitional adoption rules, companies that prospectively adopt at December 31, 2003 are only required to recognize compensation expense for those options granted during 2003, with proforma disclosure of options granted during 2002.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Compensation expense	**$ 582**	$ –	100	**$ 1,241**	$ –	100
Per boe	**$ 0.48**	$ –	100	**$ 0.27**	$ –	100

APF adopted the new Handbook section during the fourth quarter of 2003. The first three quarters of 2003 have been restated as a result of adopting the standard. APF grants options annually. Compensation expense for the first quarter relates only to options granted in 2002.

	2003				2002			
(000)	**Q1**	**Q2**	**Q3**	**Q4**	Q1	Q2	Q3	Q4
Net income (loss) as reported	**$ 13,616**	**$ 21,137**	**$ 11,405**	**$ (2,528)**	$ 2,414	$ 4,429	$ 5,463	$ (942)
Compensation expense	**(8)**	**(217)**	**(434)**	**(582)**	–	–	–	–
Restated net income (loss)	**$ 13,608**	**$ 20,920**	**$ 10,971**	**$ (3,110)**	$ 2,414	$ 4,429	$ 5,463	$ (942)

TAXES

Saskatchewan capital tax and federal large corporation tax increased by 44% during the quarter and 43% for the year ended December 31, 2003 and reflects the higher proportion of business in the Province of Saskatchewan and higher paid up capital.

Future income taxes are recorded on corporate acquisitions to the extent the book value of assets acquired, excluding goodwill, exceeds the tax basis. This future income tax liability increases the book cost of the assets acquired. It is anticipated that the future income tax liability will not be paid by APF Energy, but will instead be passed on to unitholders along with the income. Accordingly, this income tax liability will reduce each year and will be recognized as an income tax recovery at that time, to the extent that no income taxes were paid by APF Energy. In 2003, APF recorded a recovery of income taxes of $14.3 million compared with $7.1 million in 2002, leaving a balance of $64.2 million in future income taxes payable at December 31, 2003.

During 2003, the Canadian government enacted Federal income tax changes for the oil and gas resource sector as outlined in its 2003 Budget. The federal income tax changes effectively reduced the statutory tax rates for current and future periods, resulting in a significant increase in the future tax recovery (a non-cash item) compared with the first quarter and prior years. Specifically, the current 100% deductibility of the resource allowance will be completely phased out by the year 2007. During the same time frame, Crown charges will become 100% deductible and resource tax rates will decline from the current 27% to 21%. APF realized a future income tax recovery of approximately $9 million during the second quarter relating to this income tax change.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Capital and other taxes	**$ 624**	$ 433	44	**$ 2,721**	$ 1,901	43
Per boe	**$ 0.52**	$ 0.50	4	**$ 0.60**	$ 0.57	5
Recovery of future income taxes	**$ 482**	$ 198	143	**$ (14,333)**	$ (7,134)	101

INTERNALIZATION OF MANAGEMENT CONTRACT

On December 18, 2002, the unitholders approved the internalization of management and effective December 31, 2002, the Trust acquired all of the shares of APF Energy Management Inc. The acquisition resulted in the elimination of all management fees including the 3.5% fee on net operating income, a structuring fee of 1.5% on acquisitions and dispositions and the 1% residual royalty.

The total purchase price of the shares, including transaction costs, was $10.9 million, of which $4.6 million was paid in cash and $6.3 million was paid with Trust units, a portion of which are subject to certain escrow provisions. Of the total, $7.3 million was recorded as an expense in 2002.

NET EARNINGS

Earnings were up 279% to $43.0 million or $1.32 per Trust unit ($1.21 diluted) in 2003 compared with $11.4 million or $0.55 per Trust unit ($0.55 diluted) in 2002. The increase is attributable to both increases in production and commodity prices received throughout 2003.

Earnings per unit in the fourth quarter of 2003 declined as a result of increased general and administrative as well as DD&A expenses. Net earnings for the fourth quarter of 2002 decreased primarily as a result of the one-time, $7.3 million internalization expense.

Selected Annual Information (000 except per unit amounts)	**2003**	2002	2001
Total revenue	**$ 165,457**	$ 94,021	$ 69,924
Net earnings	**$ 43,048**	$ 11,365	$ 18,144
Per unit - basic	**$ 1.32**	$ 0.55	$ 1.44
Per unit - diluted	**$ 1.21**	$ 0.55	$ 1.44
Total assets	**$ 484,287**	$ 297,627	$ 198,176
Total long-term debt	**$ 98,000**	$ 88,000	$ 59,250
Distributions	**$ 68,713**	$ 37,766	$ 37,311
Per unit - basic	**$ 2.195**	$ 1.810	$ 2.980

APF's growth over the past year has been driven by the acquisitions of Hawk, Nycan and CanScot and an active development and optimization program. Growth in 2002 was positively impacted by drilling and the corporate acquisition of Kinwest Resources Inc. APF's natural gas production has increased as a percentage of total production in the past year with APF benefiting from strong gas prices, which are expected to remain strong in 2004.

SUMMARY OF QUARTERLY RESULTS

	2003				2002			
(000 except per unit amounts)	**Q1**	**Q2**	**Q3**	**Q4**	Q1	Q2	Q3	Q4
Revenue	**$ 44,502**	**$ 41,876**	**$ 39,970**	**$ 39,110**	$ 16,941	$ 21,495	$ 26,204	$ 29,380
Net earnings	**$ 13,616**	**$ 21,137**	**$ 11,405**	**$ (3,110)**	$ 2,414	$ 4,429	$ 5,463	$ (942)
Per unit - basic	**$ 0.54**	**$ 0.66**	**$ 0.32**	**$ (0.09)**	$ 0.14	$ 0.22	$ 0.25	$ (0.04)
Per unit - diluted	**$ 0.54**	**$ 0.65**	**$ 0.31**	**$ (0.09)**	$ 0.14	$ 0.22	$ 0.25	$ (0.04)

CAPITAL EXPENDITURES, ACQUISITIONS AND DISPOSITIONS

Net capital expenditures, including net property and corporate acquisitions, were $191 million in 2003 (2002 - $101 million). Of the total, $33.6 million was incurred for drilling and completions, geological, geophysical and production facilities expenditures, as APF continues to develop its asset base, with the remaining $158.1 million attributable to net property and corporate acquisitions. The 2003 corporate acquisitions of Hawk, Nycan and CanScot totalled $137.6 million, accounting for 72% of net capital expenditures during the year.

	Year Ended December 31		
(000)	**2003**	2002	% Change
Corporate acquisitions	**$ 137,622**	$ 62,143	121
Property acquisitions	**26,928**	27,958	(4)
Land acquisitions	**2,310**	616	275
Seismic	**1,070**	497	115
Drilling and completions	**24,287**	15,890	53
Production facilities	**7,749**	3,684	110
Other	**494**	908	(46)
Subtotal	**200,460**	111,696	79
Dispositions	**(9,284)**	(10,569)	(12)
Net capital expenditures	**$ 191,176**	$ 101,127	89

CASH DISTRIBUTIONS

Cash distributions for 2003 were $68.7 million, or $2.195 per Trust unit, compared with $37.8 million or $1.81 per Trust unit in 2002. During 2003, APF funded $9.3 million of capital expenditures from cash flow (2002 – $5.1 million), resulting in a payout ratio of 87% (2002 – 88%). For 2004, APF intends to maintain its historical policy of retaining a portion of available cash flow to fund capital expenditures and development initiatives, with a target range of 15% to 20%.

DISTRIBUTION REINVESTMENT PLAN

On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003. The DRIP allows eligible unitholders to direct that their monthly cash distributions be reinvested in additional Trust units at 95% of the average market price (as defined in the DRIP) on the applicable distribution date.

The DRIP includes a feature which allows eligible unitholders to elect, under the premium distribution component, to have these additional Trust units delivered to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such unitholders would have otherwise been entitled to receive on the applicable distribution date.

The DRIP also allows those unitholders who participate in either the distribution reinvestment component or the premium distribution component to purchase additional Trust units directly from APF for cash at a purchase price equal to the average market price (with no discount) in minimum amounts of $1,000 per remittance and up to $100,000 aggregate amount of remittances by a unitholder in any calendar month, all subject to an overall annual limit of 2% of the outstanding Trust units.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2003, APF had a revolving term credit facility in the amount of $150 million, with a borrowing base of $150 million, of which $98 million was drawn. The facility may be drawn down or repaid at any time, and there are no scheduled repayment terms.

On July 3, 2003, APF closed a $50.0 million 9.40% convertible unsecured subordinated debenture offering. At December 31, 2003, the balance of convertible debentures net of conversions was $48.8 million including accumulated interest of $2.3 million.

During the fourth quarter of 2003, $11.9 million (2002 - $7.6 million) was spent on development and optimization, $3.6 million (2002 - $23.5 million) on producing property acquisitions and $6.9 million (2002 - $0.8 million) was received for property dispositions.

At December 31, 2003, APF had a working capital deficit of approximately $10.2 million, compared with a working capital surplus of $0.4 million at December 31, 2002. The primary reasons for the working capital deficiency at December 31, 2003 are the significant increase in development drilling activity at December 31, 2003, resulting in higher capital expenditure accruals, along with the accrual for the STIP and provision for the semi-annual payment of debenture interest due January 31, 2004. Subsequent to year-end, APF raised $55.2 million through an equity issue and the proceeds were used to fund the working capital deficit and pay down long-term debt.

APF has budgeted the following amount for its capital program in 2004. Approximately 85% of the $40 million has been allocated for drilling and optimization initiatives.

2004 Estimated Capital Spending

Area	$ (millions)	% of Total
Central Alberta	$ 9.2	23
East Alberta/Heavy Oil	1.4	4
Southern Alberta	8.0	20
Southeast Saskatchewan	14.1	35
Coalbed Methane	7.3	18
Total	$ 40.0	100

The capital program will be funded through a combination of cash flow, distribution re-investment proceeds and debt, with a record 167 gross wells to be drilled for both conventional and coalbed methane ("CBM") opportunities.

CBM development is expected to result in the drilling of 63 gross wells in 2004. Canadian operations will focus on test wells at Doris and Timeu and completion of a 10-well pilot project in the Mannville coals at Corbett Creek. In the United States, development will continue on several projects in the Powder River Basin as APF looks to expand current operations.

UNITHOLDERS' EQUITY

At December 31, 2003, APF had 34.1 million Trust units outstanding (2002 – 22.9 million) and a market capitalization of approximately $427.1 million (2002 – $224.6 million).

In February, 2003, APF issued 4.0 million Trust units at $9.45 per Trust unit for the acquisition of Hawk Oil.

In April, 2003, APF issued 5.4 million Trust units at $10.40 per Trust unit for gross proceeds of $55.7 million. Proceeds from this issue were used to finance the purchase of Nycan and to reduce bank debt.

In June, 2003, APF issued 50,000, 9.4% convertible unsecured subordinated debentures for the acquisition of a 17% interest in Swan Hills Unit No. 1. APF signed a purchase and sale agreement with a third party, for 17% of the Unit for $91.8 million, that was subject to certain rights of first refusal ("ROFR") by another party. The party exercised the ROFR, which resulted in APF receiving 2.55% of the Unit for approximately $15.9 million. The remainder of the debenture issue was used to reduce bank debt and ultimately to partially fund the acquisition of CanScot in September.

In September, 2003, APF issued 1.3 million Trust units at $11.50 per Trust unit for the acquisition of CanScot.

In December, 2003, APF issued 140,710 Trust units pursuant to the new Premium Distribution Reinvestment Plan for proceeds of $1.60 million (2002 - $nil).

During 2003, 199,005 Trust units (2002 - 61,777) were issued pursuant to the Trust unit incentive plan for total proceeds of $1.8 million (2002 - $0.5 million). An additional 107,998 units were issued during the year upon conversion of debentures.

On February 4, 2004, APF closed the issue of 4.8 million Trust units at a price of $11.60 each for gross proceeds of $55.3 million. The proceeds of this offering were used to fund working capital and pay down debt.

Commitments and Contingencies

APF is involved in certain legal actions that occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

APF has compiled a capital budget that has been approved by the Board. The budget forecast is a best estimate of the projects that APF intends to undertake during the year, but does not constitute a legal or contractual obligation to do so. For properties that APF does not operate, a commitment to complete a project at a given future date may be required from the operator. As of the first quarter of 2004, APF has not committed any material funds for these projects.

(000)	2004	2005	2006	2007	2008
Lease commitments	$ 773	$ 756	$ 710	$ 706	$ 359

BUSINESS RISKS

APF is faced with a number of business risks that are inherent in the oil and gas industry and which can have an impact on distributions to unitholders. To mitigate these risks, APF follows appropriate policies and procedures in its ongoing operations and in its long-term strategic planning.

Financial and market risks associated with commodity prices and foreign currency exchange rates are mitigated through APF actively managing the sale of its own production to maximize price and through the use of a hedging program to hedge commodity prices and foreign currency rates with creditworthy counterparties. Hedging is employed as a risk management tool and not for speculation. APF entered into three interest rate swaps during 2003, which expire at various dates in 2005.

There are inherent operational risks associated with oil and natural gas production, relating to the ability to produce, process and transport oil and natural gas; the ability to replace production and maintain reserves and environmental and safety risks associated with well and production facilities. To mitigate these risks, APF employs a strategy of operating a significant portion of its production, thereby providing greater control over operations; APF employees and contractors adhere to APF's safety program and keep current on changes to operating practices, and APF maintains insurance coverage to minimize the impact of operational losses.

APF's ability to grow is dependent upon its ability to raise debt and equity capital in the Canadian capital markets. APF has lines of credit with three Canadian chartered banks that provide debt financing for acquisitions. The issue of new equity allows APF to pay down debt while continuing to make acquisitions. If Canadian debt or equity markets were to become inaccessible to APF, it may affect the ability of APF to continue to replace production and maintain distributions.

Changing government royalty regulations, income tax laws, incentive programs relating to the oil and gas industry and changes in securities legislation are all examples of regulatory changes that can affect APF's activities.

APF's cash flow is influenced by changes in a number of variables. Sensitivities to 2004 pre-hedging cash flows are as follows:

Variable	Change	Cash flow Impact ($000)	Change Per Unit
Crude oil price	$U.S. 1 per bbl	2,360	$0.07
Natural gas price	$Cdn. 0.10/mcf	1,200	$0.04
$U.S./$Cdn. exchange rate	$0.01	2,000	$0.06
Interest rate	1.00%	1,000	$0.03
Crude oil production	100 bbl/d	1,095	$0.03
Natural gas production	1 mmcf/d	1,500	$0.04

Critical Accounting Estimates

In order to prepare the financial statements in conformity with generally accepted accounting principles in Canada, APF has to make estimates and assumptions. The matters described below are considered to be the most critical in understanding the judgments that are involved in preparing the financial statements and the uncertainties that could impact the amounts reported on the results of operations, financial condition and cash flows. Accounting policies are described in Note 2 to the financial statements.

Estimation of oil and gas reserves

Oil and gas reserves have been estimated in accordance with National Instrument 51-101. Estimates of oil and gas reserves are inherently imprecise and represent only approximate amounts and are subject to future revision, as they are based on available reservoir data, prices and costs as of the date the estimate is made. Accordingly, the financial measures that are based on estimated reserves are also subject to change.

Depreciation, depletion and amortization

Proved reserves are used when calculating the unit-of-production rates used for depreciation, depletion and amortization for oil and gas assets including tangible fixed assets related to hydrocarbon production activities. The amount of depreciation is based on the units of production over the proved developed reserves of the relevant field during the time period. Unproved properties are amortized as required by particular circumstances. Other tangible fixed assets are generally depreciated on a straight-line basis over their estimated useful lives of five to ten years.

Ceiling test

The carrying amounts of fixed assets are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amounts for those properties may not be recoverable. If assets are determined to be impaired, the carrying amounts of those assets are written down to fair value. For this purpose, assets are assigned to a cost pool based on the country in which the activity has occurred. Estimates of future cash flows of assets related to hydrocarbon production activities are based on proved reserves determined in accordance with National Instrument 51-101.

Decommissioning and restoration costs

Provisions are held for the future decommissioning and restoration of oil and natural gas production facilities and pipelines at the end of their economic lives. Estimated decommissioning and restoration costs are based on current requirements, technology and price levels. Most of these obligations are many years in the future and the precise requirements that will have to be met are uncertain because technologies and costs as well as political, environmental, and safety expectations are subject to change.

RECENT ACCOUNTING AND REGULATORY GUIDELINE CHANGES

Full Cost Accounting Guideline

In September, 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost" to replace CICA Accounting Guideline 5. The new guideline proposes amendments to the ceiling test; as well, it requires additional disclosures relating to critical accounting estimates for impairment and depletion, depreciation and amortization.

The new guideline is effective for fiscal years beginning on or after January 1, 2004; however, APF has elected to adopt the standard early at December 31, 2003. There are no material financial impacts resulting from the adoption of this standard.

Asset Retirement Obligations

The Canadian Institute of Chartered Accountants ("CICA") issued Section 3110 "Asset Retirement Obligations" in March, 2003. The new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements. The Canadian standard will be effective for fiscal years beginning on or after January 1, 2004.

Under this standard, these obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over the life of the assets.

APF is currently evaluating the impact of this new standard and will adopt it during the first quarter of 2004.

Hedging Relationships

In December, 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003.

The new guideline addresses hedging transactions for the purposes of applying hedge accounting and establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue hedge accounting for positions hedged with derivatives.

A large portion of APF's current crude oil portfolio is a light sour or medium crude priced at Cromer and currently does not qualify as effective against the WTI light sweet crude price that APF currently hedges. As a result, APF does not anticipate applying hedge accounting against its existing crude oil hedge contracts.

In order for the currency hedge to qualify as effective, it must be associated with either U.S. denominated debt or U.S. denominated revenues. At December 31, 2003, APF did not have any U.S. denominated debt and the settlement terms for the foreign currency hedge is not aligned to the settlement dates of the WTI contracts. As a result, APF does not anticipate applying hedge accounting against its foreign currency hedge contracts.

The majority of APF's gas hedges are priced at AECO, which do correlate with existing gas revenue streams. APF is evaluating the impact of the standard with respect to gas contracts, and expects to finalize its decision to apply hedge accounting in the first quarter of 2004.

Variable Interest Entities

In June, 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. APF is assessing the impact of this new guideline.

Continuous Disclosure Rules

Effective March 30, 2004, all reporting issuers in Canada were to be subject to new continuous disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective, generally, for fiscal years beginning on or after January 1, 2004. The Instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and the Annual Information Form ("AIF").

The Instrument also proposes enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for APF to mail annual and interim financial statements and MD&A to unitholders, but rather, these documents are to be provided on an "as requested" basis. APF continues to assess the implications of this new instrument, which will be implemented at March 30, 2004.

Accounting for Convertible Debentures

In June, 2003, the CICA approved an amendment to Handbook section 3860 "Financial Instruments – Disclosure and Presentation". Under the previous guidelines, debt obligations that could be settled with the entity's own equity instruments could be classified as equity, and related interest was treated as a reduction of unitholders' equity.

The amendment would require certain obligations that must or could be settled with an entity's own equity instruments to be presented as a liability, with the corresponding interest being booked through the income statement. The amendment is effective for all fiscal years starting after November 1, 2004.

Outlook

APF remains committed to its strategy of buying well and exploiting its land base through development drilling, recompletions and field optimizations. For 2004, a total of 167 gross wells have been budgeted for drilling. APF has allocated $40 million to its capital expenditure budget for the year with 85% of the funds being directed to drilling and development of conventional properties. Throughout 2004, APF will continue to expand its CBM pilot projects in Central Alberta. In total, $7 million has been identified in the capital budget for CBM initiatives in both Canada and the U.S. With low production declines and the potential for higher rates of return than conventional production, APF feels CBM presents a very attractive opportunity and is ideally suited for the trust structure.

APF will continue to pursue acquisitions that will be accretive on a per unit basis to cash flow, production, reserves and net asset value. APF is committed to maintaining stable cash distributions over the long-term. In order to mitigate the commodity price risk that is inherent to the oil and gas sector, APF will continue to actively hedge production. APF believes that over the long term, outlook for both crude oil and natural gas pricing remains strong.

DISCLAIMER

Certain statements in this document are "forward-looking statements" including outlook on oil and gas prices, royalty rates, operating expenses, estimates of future production, estimated completion dates of construction and development projects, business plans for drilling and exploration, estimated amounts and timing of capital expenditures and anticipated future debt levels. Information concerning reserves contained in this material may also be deemed to be forward-looking statements as such estimates involving the implied assessment that the resources described can be profitably produced in the future. These statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ from those anticipated by APF Energy Trust and APF Energy Inc. These risks include, but are not limited to: the risks of the oil and gas industry (e.g., operational risks in exploration for; development and production of crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; and health, safety and environmental risks); risks in conducting foreign operations (e.g., political and fiscal instability in nations where APF Energy does business); the possibility that government policies may change or governmental approvals may be delayed or withheld; and price and exchange rate fluctuations. These and other risks are described in APF Energy's reports that are on file with Canadian securities regulatory authorities. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors and management's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to APF or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. APF assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the consolidated financial statements and the preparation of all other financial information included in the annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, and where applicable, amounts based on management's best estimates and judgment.

Management has established procedures and systems of internal control designed to provide reasonable assurance that assets are safeguarded and that accurate financial information is produced in a timely manner.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and, through its Audit Committee, ensuring that management fulfills its responsibilities for financial reporting. The Audit Committee meets periodically with management and the external auditors to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors. PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, appointed by the unitholders of APF Energy Trust, have audited the consolidated financial statements in accordance with Canadian generally accepted auditing standards. PricewaterhouseCoopers LLP have full and free access to the Audit Committee.

Martin Hislop
Chief Executive Officer

Alan MacDonald
Vice President, Finance

Calgary, Alberta
February 20, 2004

Auditors' Report

To the Unitholders of APF Energy Trust

We have audited the consolidated balance sheets of APF Energy Trust as at December 31, 2003 and 2002 and the consolidated statements of operations and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta
February 20, 2004

Consolidated Balance Sheets

As at December 31	**2003**	2002
	($000)	($000)
ASSETS		
Current assets		
Cash	**1,381**	950
Accounts receivable	**27,542**	21,111
Other current assets	**3,506**	2,779
	32,429	24,840
Site restoration fund (note 6)	**2,342**	784
Goodwill (note 7)	**48,230**	11,476
Property, plant and equipment (note 5)	**401,286**	260,527
	484,287	297,627
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**36,711**	16,943
Due to APF Energy Management Inc. (note 14)	–	3,923
Cash distribution payable	**5,963**	3,565
	42,674	24,431
Future income taxes (note 13)	**64,222**	39,625
Long-term debt (note 8)	**98,000**	88,000
Site restoration liability (note 6)	**10,410**	6,227
	215,306	158,283
UNITHOLDERS' EQUITY		
Unitholders' investment account (note 9)	**324,317**	214,405
Contributed surplus (note 10)	**1,241**	–
Accumulated earnings	**78,637**	35,589
Accumulated cash distributions (note 4)	**(179,363)**	(110,650)
Convertible debentures (note 12)	**46,466**	–
Accumulated interest on convertible debentures	**(2,317)**	–
	268,981	139,344
	484,287	297,627
Contingencies and commitments (note 17)		

See accompanying notes to consolidated financial statements

Approved by the Board of Directors

Don Engle
Director

Martin Hislop
Director

Consolidated Statements of Operations and Accumulated Earnings

For the years ended December 31	2003	2002
	($000)	($000)
Revenue		
Oil and gas	**163,532**	92,345
Royalties expense, net of ARTC	**(32,473)**	(18,707)
Other	**1,925**	1,676
	132,984	75,314
Expenses		
Operating	**32,370**	19,748
General and administrative (note 14)	**10,023**	4,635
Stock-based compensation expense (note 10)	**1,241**	–
Management fee (note 14)	**–**	1,976
Interest on long-term debt	**4,171**	2,834
Depletion, depreciation and amortization	**50,417**	30,201
Site restoration	**3,327**	2,087
Capital and other taxes	**2,720**	1,901
Internalization of management contract (note 14)	**–**	7,297
	104,269	70,679
Income before income taxes and minority interest	**28,715**	4,635
Recovery of future income taxes (note 13)	**14,333**	7,133
Income before minority interest	**43,048**	11,768
Minority interest (note 14)	**–**	403
Net income	**43,048**	11,365
Accumulated earnings – beginning of year	**35,589**	24,224
Accumulated earnings – end of year	**78,637**	35,589
Net income per unit – basic ($)	**1.32**	0.55
Net income per unit – diluted ($)	**1.21**	0.55

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

For the years ended December 31	2003 ($000)	2002 ($000)
CASH PROVIDED BY (USED IN)		
Operating activities		
Net income for the year	**43,048**	11,365
Items not affecting cash		
Depletion, depreciation and amortization	**50,417**	30,200
Minority interest	**–**	403
Future income taxes	**(14,333)**	(7,133)
Internalization of management contract	**–**	7,037
Stock-based compensation expense	**1,241**	–
Site restoration	**3,327**	2,087
Site restoration expenditures (note 6)	**(374)**	(171)
	83,326	43,788
Net change in non-cash working capital items		
Accounts receivable	**1,016**	(7,994)
Other current assets	**(398)**	(328)
Accounts payable and accrued liabilities	**9,138**	6,537
Due to related party / APF Management	**(3,923)**	(1,088)
Cash distribution payable	**2,398**	1,227
	8,231	(1,646)
Site restoration fund contribution	**(1,558)**	(754)
Cash distributions	**(68,713)**	(37,766)
	21,286	3,622
Investing activities		
Purchase of Hawk Oil	**(3,456)**	–
Purchase of Nycan Energy	**(34,287)**	–
Purchase of CanScot Resources	**(20,516)**	–
Purchase of Kinwest	**–**	(17,361)
Additions to property, plant and equipment	**(33,601)**	(20,979)
Purchase of oil and natural gas properties	**(29,238)**	(28,574)
Proceeds on sale of properties	**9,284**	10,569
Changes in non-cash working capital-investing items	**2,961**	(560)
	(108,853)	(56,905)
Financing activities		
Issue of units for cash	**57,272**	32,250
Issue of units for cash upon exercise of stock options	**1,749**	554
Unit issue costs	**(3,467)**	(1,861)
Convertible debentures – net of costs	**47,681**	–
Interest on convertible debentures	**(2,317)**	–
(Repayment)/proceeds on issue of long-term debt – net	**(12,920)**	21,650
Distribution to 1% minority interest	**–**	(403)
	87,998	52,190
Change in cash during the year	**431**	(1,093)
Cash – beginning of year	**950**	2,043
Cash – end of year	**1,381**	950
Supplemental information (note 16)		

See accompanying notes to consolidated financial statements

The objective and integrity of data in these financial statements, including estimates and judgements relating to matters not concluded by year-end, are the responsibility of management of APF Energy Trust ("Trust"). In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies.

NOTE 1 BASIS OF PRESENTATION

APF Energy Trust (the "Trust")
The Trust is an open-end investment trust under the laws of the Province of Alberta.

APF Energy Inc. ("Energy")
Energy was incorporated and organized for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties, including certain initial properties and granting a royalty thereon to the Trust.

APF Energy Limited Partnership ("LP")
LP was formed for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties and granting a royalty thereon to the Trust.

Tika Energy Inc. ("Tika")
Tika is a wholly owned subsidiary of Energy and was incorporated in Wyoming for the purpose of acquiring, developing, exploiting and disposing of coalbed methane gas properties in the United States.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Consolidation
These consolidated financial statements include the accounts of the Trust, Energy, LP and Tika and are referred to collectively as "APF".

Revenue recognition
Revenue associated with the sale of crude oil, natural gas, and natural gas liquids owned by the Trust are recognized when title passes from the Trust to its customers.

Goodwill
The Trust records goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or as events occur that could indicate an impairment. Impairment is recognized based on the fair value of APF compared to the net book value of APF. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Property, plant and equipment – oil and natural gas
APF follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in a cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements, which extend the economic life of the property, plant and equipment are capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more.

Ceiling test
The Trust places a limit on the aggregate carrying value of property, plant and equipment. An impairment is recognized if the carrying amount of the property, plant and equipment exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

The Trust determines if there is an impairment by comparing the carrying amounts of the property, plant and equipment to an amount equal to the fair value of the property, plant and equipment. Any excess carrying value above the fair value of the Trust's future cash flows would be recorded as a permanent impairment. The cost of unproved properties are excluded from the ceiling test calculation and is subject to a separate impairment test.

Depletion, depreciation and amortization

Depletion, depreciation and amortization of oil and natural gas assets including tangible equipment is calculated using the unit-of-production method based on the working interest share of total proven reserves before royalties. Reserves estimates are calculated in accordance with National Instrument 51-101 and relative volumes of petroleum and natural gas reserves and production, before royalties are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Site restoration and abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method. Actual site restoration costs are charged against the accumulated provision.

Other equipment

All other equipment is carried at cost and is depreciated over the estimated useful life of the assets at annual rates varying from 10% to 30%.

Joint ventures

Substantially all oil and natural gas production and exploitation activities are conducted jointly with others. Accordingly, the accounts reflect APF's proportionate interest in these activities.

Trust per unit calculations

The Trust has applied the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

Cash distributions declared per unit amount are based on actual distribution for units outstanding at the time of declaration.

Unit based compensation

APF has established a Trust Unit Incentive Rights Plan (the "Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of APF. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to unitholders to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the financial statements for unexercised rights.

The Trust has a Trust Unit Incentive Rights Plan which is described in note 10.

Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in earnings in the period of change with a corresponding increase or decrease in contributed surplus. This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying Trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights exercised or outstanding at the date of the financial statements.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital. If Trust Units or Trust Unit options are repurchased from employees, the excess of the consideration paid over the carrying amount of the Trust Units or Trust Unit options cancelled is charged to accumulated earnings.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, APF accounts for actual forfeitures as they occur.

Cash distributions
Cash distributions are calculated on an accrual basis and are paid to the Unitholders based upon funds available for distribution.

Income taxes
The Trust is an inter vivos trust for income tax purposes. As such, the Trust is taxable on any taxable income which is not allocated to the Unitholders. The Trust intends to allocate all taxable income to Unitholders. Should the Trust incur any income taxes, the funds available for distribution will be reduced accordingly. Provision for income taxes is recorded in Energy at applicable statutory rates. Provision for income taxes is recorded in Energy using the liability method of accounting whereby the future income tax effect of any difference between the accounting and income tax basis of an asset or liability is booked.

Management estimates
The consolidated financial statements include certain management estimates that may require accounting adjustments based on future occurrences. The most significant estimates relate to depletion, depreciation and amortization and ceiling test calculations for capital assets including future abandonment liabilities as they are based on engineering reserve estimates and estimated future costs.

NOTE 3 CHANGE IN ACCOUNTING POLICIES

Accounting Guideline 16
Effective December 2003, the Trust adopted AcG-16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants which replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry".

There were no changes to net income, property, plant and equipment or any other reported amounts in the financial statements as a result of adopting this guideline.

Stock based compensation
APF elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, APF must account for compensation expense based on the fair value of rights granted under its' unit-based compensation plan. As APF is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the grant date or at the date of the financial statements for unexercised rights as described in Note 2.

For rights granted in 2002, APF has elected to disclose pro forma results as if the amended accounting standard had been adopted retroactively. As a result of adopting this standard, net income for the year ended December 31, 2003 decreased by $1.2 million and contributed surplus increased by $1.2 million.

See Note 10 for additional information regarding the nature of the plan and the associated compensation expense.

NOTE 4 CASH DISTRIBUTIONS AND ACCUMULATED CASH DISTRIBUTIONS

The following table is the calculation of cash distributions and accumulated cash distributions:

($000, except per unit amounts)	2003	2002
	$000	$000
Oil and gas sales	163,532	92,345
Other	1,925	1,676
Gross overriding royalties and lessors' royalties	(13,109)	(7,802)
	152,348	86,219
Less		
Operating costs	32,370	19,748
General and administrative	9,362	4,317
Management fees	–	1,976
Debt service charges (including interest and principal)	4,171	2,834
Site restoration fund contribution	1,932	925
Capital and other taxes	2,720	1,901
Capital expenditures funded from cash flow	9,326	5,144
	59,881	36,845
Income subject to the royalty	92,467	49,374
99% of income subject to the royalty	91,542	48,880
Crown charges, net of Alberta Royalty Tax Credit	(19,851)	(10,796)
Interest on convertible debentures	(2,317)	–
General and administrative costs of the Trust	(661)	(318)
Cash available to be distributed	68,713	37,766
Cash distributed to date	62,750	34,201
Cash distribution payable	5,963	3,565
Actual cash distribution declared per unit ($)	2.195	1.810
Opening accumulated cash distributions	110,650	72,884
Distribution declared and paid	62,750	34,201
Distribution declared and payable	5,963	3,565
Closing accumulated cash distributions	179,363	110,650

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

($000)	2003	2002
Property, plant and equipment	531,365	340,189
Accumulated depletion, depreciation and amortization	(130,079)	(79,662)
	401,286	260,527

The calculation of 2003 depletion, depreciation and amortization included an estimated $25.0 million (2002 – $16.7 million) for future development costs associated with proved undeveloped reserves and excluded $10.8 million (2002 – $7.9 million) for the estimated value of unproved properties and coalbed methane projects currently in the development stage. General and administration costs of $458,000 associated with coalbed methane projects have been capitalized (2002 – $nil).

The Trust performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of property, plant and equipment. The crude oil and natural gas futures prices are management's best estimates and are based on information obtained from third parties and were adjusted for commodity differentials specific to the Trust. Future prices were obtained for the period of 2004 to 2008 inclusive and then escalated based on escalation factors in the Trust's year-end independent reserves evaluation.

Based on these assumptions, which are shown below, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's property, plant and equipment at December 31, 2003.

Year	WTI Oil ($U.S./bbl)	Foreign exchange rate ($U.S./$Cdn.)	WTI Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2004	30.18	0.77	39.43	5.72
2005	27.44	0.76	36.12	5.42
2006	26.67	0.75	35.33	5.27
2007	26.61	0.75	35.43	5.23
2008	26.78	0.75	35.77	5.18
2009 – 2014 (1)	–			–
Remainder (2)	1.5%			1.5%

(1) Percentage change represents the average for the period noted.

(2) Percentage change represents the change in each year after 2014 to the end of the reserve life.

NOTE 6 SITE RESTORATION FUND/LIABILITY

Energy and the LP are responsible for future site restoration costs on all properties. At December 31, 2003 the future undiscounted estimated costs for the site restoration liabilities were $31,198,000 (2002 – $29,858,000), of which $10,410,000 has been provided for. The current year expense charged to the provision was $3,327,000 (2002 – $2,087,000). Actual payments for abandonment in 2003 were $374,000 (2002 – $171,000).

A site restoration fund was established to fund future site reclamation and abandonment costs. Contributions to the site restoration fund during the year totalled $1,932,000 (2002 – $925,000) and have been deducted in calculating the income subject to the royalty.

Contributions to the site restoration fund are determined annually by management and are based on the average of the next three years expected site restoration expenses, as determined by the independent engineers.

NOTE 7 ACQUISITIONS

Effective February 5, 2003, Energy acquired all of the issued and outstanding shares of Hawk Oil Inc. ("Hawk Oil"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Bank overdraft	(5)
Other working capital	(629)
Property, plant and equipment	57,146
Goodwill	11,078
Debt assumed	(7,900)
Site restoration liability	(263)
Future income taxes	(18,266)
Total net assets acquired	41,161
Financed by	
Cash	2,856
Trust units issued (3,990,461 Trust units)	37,710
Acquisition costs	595
Total consideration	41,161

Notes To Consolidated Financial Statements

Effective April 28, 2003, Energy acquired all of the issued and outstanding shares of Nycan Energy Corp. ("Nycan"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Cash	212
Other working capital	716
Property, plant and equipment	47,495
Goodwill	8,792
Debt assumed	(8,870)
Site restoration liability	(580)
Future income taxes	(13,266)
Total net assets acquired	34,499
Financed by	
Bank debt	34,374
Acquisition costs	125
Total consideration	34,499

Effective September 26, 2003, Energy acquired all of the issued and outstanding shares of CanScot Resources Ltd. ("CanScot"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Cash	156
Other working capital	22
Property, plant and equipment	32,980
Goodwill	16,884
Debt assumed	(6,150)
Site restoration liability	(388)
Future income taxes	(7,399)
Total net assets acquired	36,105
Financed by	
Bank debt	19,689
Trust units issued (1,342,004 Trust units)	15,433
Acquisition costs	983
Total consideration	36,105

Effective May 30, 2002, Energy acquired all of the issued and outstanding shares of two private corporations, Kinwest Energy Inc. ("Kinwest") and Kinwest's joint venture partner (collectively the "Kinwest Acquisition"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Working capital	1,641
Property, plant and equipment	63,483
Goodwill	11,476
Debt assumed	(10,146)
Site restoration liability	(673)
Future income taxes	(15,410)
Total net assets acquired	50,371
Financed by	
Cash	13,042
Trust units issued (3,385,510 Trust units)	36,056
Acquisition cost – due to related party	838
Acquisition costs	435
Total consideration	50,371

NOTE 8 LONG-TERM DEBT

($000)	**2003**	2002
Bank loans	**98,000**	88,000

At December 31, 2003, APF had a $150.0 million revolving term credit facility with a syndicate of Canadian resident financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The debt bears interest based on a sliding scale tied to APF's debt to cash flow ratio, from a minimum of the bank's prime rate plus 0.125% to a maximum of the prime rate plus 1.625% (2002 – prime rate plus 1.5%) or where available, at Banker's Acceptances rates plus a stamping fee of 1.125% to 2.0% (2002 – 1.125% to 2.5%). The debt is secured by a $300.0 million demand debenture containing a first fixed charge on all the petroleum and natural gas assets of APF and an assignment of book debts and material gas contracts. At December 31, 2003, the interest rate was bank prime of 4.5% plus 0.125% (2002 – 4.5% plus 0.25%).

APF has the option to extend the revolving period for an additional 364 days by giving notice to the lenders no earlier than 180 days and no less than 90 days prior to the end of the revolving period. If the revolving period is not extended, the outstanding principal will be converted to a one-year non-revolving term loan commencing on the day immediately following the end of the then current revolving period. During the one-year term period, APF will pay 1/6th of the outstanding principal on the 180th day after the commencement of the one-year term period and 1/12th of the outstanding principal on the 90th day thereafter.

NOTE 9 UNITHOLDERS' INVESTMENT ACCOUNT

	2003		2002	
		Amounts		Amounts
	Units	**($000)**	Units	($000)
Balance – Beginning of year	**22,942,417**	**214,405**	15,583,880	141,069
Issued to acquire Hawk Oil	**3,990,461**	**37,710**	–	–
Issued to acquire CanScot Resources	**1,342,004**	**15,433**	–	–
Issued to acquire Kinwest	**–**	**–**	3,385,510	36,056
Issued for cash	**5,351,645**	**55,670**	3,303,665	32,250
Cost of units issued	**–**	**(3,467)**	–	(1,861)
Distribution reinvestment program	**140,710**	**1,602**	–	–
Issued on conversion of debentures	**107,998**	**1,215**	–	–
Issued under management internalization	**–**	**–**	608,185	6,337
Issued on exercise of options/rights	**199,005**	**1,749**	61,177	554
Balance – End of year	**34,074,240**	**324,317**	22,942,417	214,405

The holders of Units are entitled to vote at any meeting of the Unitholders.

The per unit calculations are based on the weighted average number of units outstanding during the year of 30,970,093 units (2002 – 20,470,210 units). In computing diluted net income per unit, 334,077 units were added to the weighted average number of units outstanding during the year (2002 – 57,569) for the dilutive effect of employee options and rights to acquire Trust units. In addition, 4,336,444 units were added (2002 – nil) for the dilutive effect of the convertible debentures for a total weighted average number of units for 2003 of 35,640,614 (2002 – 20,527,779).

Net income for 2003 has been adjusted by $2,317,000 (2002 – $nil) for the interest accrued on the convertible debenture for purposes of calculating basic earnings per unit.

In 1999, the Trust created a Unitholders' Rights Plan and authorized the issuance of one right in respect of each Unit outstanding. Each right would allow Unitholders in specified circumstances, to acquire, on payment of an exercise price of $50.00, the number of Units having an aggregate market price equal to twice the exercise price of the rights.

Effective with the December 2003 distribution, the Trust initiated a premium distribution reinvestment plan ("DRIP"). The DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95% of the average market price as defined in the plan ("Regular DRIP").

The premium distribution component permits eligible unitholders to elect to receive 102% of the cash the unitholder would otherwise have received on the distribution date ("Premium DRIP"). Participation in the Regular DRIP and Premium DRIP is subject to proration by the Trust. Unitholders who participate in either the Regular DRIP or the Premium DRIP are also eligible to participate in the optional unit purchase plan as defined in the DRIP.

NOTE 10 TRUST UNIT INCENTIVE RIGHTS PLAN

Pursuant to a Trust Unit Incentive Plan dated December 17, 1996 and amended February 1, 1998 (the "Plan"), employees, directors and long-term consultants may be granted options to acquire Units of the Trust. The exercise price for each option was the market price of the Units at the time the option was granted. Options granted prior to February 1, 1998 vested immediately, while options granted on or after February 1, 1998 vest in one-third increments on the first, second and third anniversaries of their grant. The maximum term for options is five years. This Plan was terminated in 2001 and replaced with a new Trust Unit Incentive Rights Plan ("Rights Plan").

Under the Rights Plan, employees, directors and long-term consultants may be granted rights to purchase Units of the Trust. The initial exercise price of rights granted under the Rights Plan may not be less than the current market price of the Trust Units as of the date of the grant and the maximum term of each right is not to exceed ten years. The exercise price is to be adjusted downwards from time to time by the amount, if any, that distributions to Unitholders in any calendar quarter exceed a percentage of APF's net book value of property, plant and equipment, as determined by the Trust.

APF recorded compensation expense and contributed surplus of $1,241,000 for rights issued in 2003, based on the year-end unit price of $12.54.

For rights granted in 2002, APF has elected to disclose proforma results as if the amended accounting standard has been applied retroactively. For the year ended December 31, 2003, APF's net income would have decreased by $950,000 for the estimated compensation cost associated with rights granted under the plan between January 1 and December 31, 2002 as follows:

($000)	2003	2002
Net income as reported	43,048	11,365
Less: Compensation expense for rights issued in 2002	(950)	–
Pro forma net income	42,098	11,365
Basic net income per Trust unit		
As reported	1.32	0.55
Proforma	1.28	0.55
Diluted net income per Trust unit		
As reported	1.21	0.55
Proforma	1.18	0.55

No compensation expense has been recorded for 2002 as the adjusted exercise price of the rights exceeded APF's market price at December 31, 2002.

Net income in the basic per Trust unit calculation has been reduced by interest on the convertible debentures of $2.3 million for purposes of calculating the basic net income.

NOTE 11 RIGHTS AND OPTIONS OUTSTANDING

A summary of the status of the Plan as of December 31, 2003 and 2002 is as follows:

Trust Unit Options	Units	2003 Weighted average price ($)	Units	2002 Weighted average price ($)
Outstanding – beginning of year	244,029	9.13	330,540	9.32
Granted	–	–	–	–
Exercised	(106,786)	8.55	(58,677)	9.05
Forfeited	(10,774)	9.42	(27,834)	11.62
Outstanding – end of year	126,469	9.59	244,029	9.13
Options exercisable – end of year	60,173	9.48	76,488	8.72

The following table summarizes options information under the Plan outstanding at December 31, 2003:

Range of Exercise prices ($)	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price ($)	Number exercisable December 31, 2003	Weighted average price ($)
7.00 – 7.99	700	1.18	7.15	700	7.15
8.00 – 9.00	6,899	0.15	8.00	6,899	8.00
9.01 – 10.00	118,870	2.17	9.70	52,574	9.70
	126,469	2.10	9.59	60,173	9.48

Rights plan

During the year, the Trust granted 1,538,250 rights (2002 – 441,233) under the Rights Plan to employees and directors to purchase Trust units at prices ranging from $9.67 to $11.54 (2002 – $9.73 to $10.80) per Trust unit.

A summary of the Rights Plan at December 31, 2003 and 2002 is as follows:

		2003		2002
	Number of rights	**Weighted average price ($)**	Number of rights	Weighted average price ($)
Balance – beginning of year	**429,333**	**9.37**	–	–
Granted	**1,538,250**	**9.78**	441,233	9.86
Exercised	**(92,219)**	**9.05**	(2,500)	9.73
Cancelled	**(51,034)**	**9.67**	(9,400)	9.73
Balance before reduction of exercise price	**1,824,330**	**9.72**	429,333	9.86
Reduction of exercise price	**–**	**0.63**	–	0.49
Balance – end of year	**1,824,330**	**9.09**	429,333	9.37
Rights exercisable – end of year	**47,221**	**8.58**	–	–

The following table summarizes information about the Rights Plan as at December 31, 2003:

Range of Exercise prices ($)	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price ($)	Number exercisable December 31, 2003	Weighted average price ($)
8.00 – 9.00	222,180	8.17	8.40	40,721	8.49
9.01 – 10.00	1,508,623	9.27	9.06	6,500	9.18
10.01 – 11.00	10,858	9.45	10.45	–	–
11.01 – 12.00	82,669	9.50	11.31	–	–
	1,824,330		9.09	47,221	8.58

NOTE 12 CONVERTIBLE DEBENTURES

On July 3, 2003, APF issued $50.0 million of unsecured subordinated convertible debentures ($47.7 million net of issue costs) with a 9.40% coupon rate maturing July 31, 2008. Interest is paid semi-annually on January 31 and July 31. The debentures may be converted into Trust units at the option of the holder at a conversion price of $11.25 per Trust unit prior to July 31, 2008 and may be redeemed by APF under certain circumstances. The debentures and related interest obligations have been classified as equity on the consolidated balance sheet as APF may elect to satisfy interest and principal obligations by the issuance of Trust units. During the year, $1.2 million of convertible debentures were converted into 107,998 Trust units.

NOTE 13 INCOME TAXES

Energy and the LP have approximately $70.0 million of unused tax pools at December 31, 2003 ($60.4 million – December 31, 2002) available to be used to offset future taxable income subject to certain restrictions of the Income Tax Act.

Energy had approximately $22.3 million in non-capital losses at December 31, 2003 ($15.3 million – December 31, 2002) of which approximately $945,000 expire in 2005 and the remainder through 2010.

The Unitholders are responsible for their own income taxes. Distributions will be a combination of taxable income and a return of capital in the year received. Generally, when the Trust has no taxable income prior to the deduction of distributions, distributions will not be taxable but will be a return of capital which reduces the Unitholders' adjusted cost base in those years.

Distributions paid are deducted from taxable income only to the extent needed to reduce taxable income in the Trust to zero. Generally, the distributions deducted for the Trust tax return are taxable income to the Unitholders.

($000)	**2003**	2002
Income before income taxes	**28,715**	4,635
Statutory tax rate	**42.75%**	43.5%
Expected tax provision	**12,276**	2,016
Effect on income tax of		
Net income of the Trust	**(21,002)**	(12,603)
Resource allowance	**(2,250)**	(595)
Non-deductible crown charges	**669**	47
Internalization of management contract	**–**	3,174
Capital tax	**1,163**	827
Rate reduction	**(3,717)**	–
Other	**(1,472)**	–
Provision for future income taxes	**(14,333)**	(7,134)
The future tax recorded on the balance sheet results from		
Capital assets in excess of tax value	**72,725**	46,282
Future tax losses that are likely to be utilized	**(8,503)**	(6,657)
	64,222	39,625

Taxable income of the Trust is comprised of income from royalty, adjusted for crown royalties and resource allowance, less deductions for Canadian oil and natural gas property expense (COGPE), which is claimed at a rate of 10% on a declining balance basis and issue costs which are claimed at 20% per year on a straight-line basis. Any losses that occur in the Trust must be retained in the Trust and may be carried forward and deducted from taxable income for a period of seven years. The COGPE during 2003 resulted from the purchase of royalty interests.

The amount of COGPE and issue costs remaining in the Trust are approximately $122.3 million.

NOTE 14 RELATED PARTY TRANSACTIONS

Internalization of management

On December 18, 2002, Unitholders approved the acquisition of APF Energy Management Inc. (the "Manager"), effective January 1, 2003. Total consideration for the transaction consisted of a cash payment of $3.9 million and the issuance of 608,185 Trust Units to the shareholders of the Manager as detailed below:

($000)	
Net assets acquired	
Cash	419
Working capital	629
Property, plant and equipment	4,512
Future income taxes	(1,917)
Internalization of management contract	7,297
Total net assets acquired	10,940
Total consideration	
Cash	3,923
Trust units issued	6,337
Transaction costs	680
Total purchase price	10,940

Although the transaction did not close until January 3, 2003, all of the major conditions, including unitholder and regulatory approval, had been obtained by December 31, 2002. Accordingly, the transaction was accounted for as if it had closed on December 31, 2002.

The consideration paid through the issue of Trust Units is partially subject to escrow restrictions. In the case of Mr. Martin Hislop, Chief Executive Officer, 100% of the 150,526 Trust Units issued are subject to escrow for 3 years, released as to one third on each anniversary date of the transaction. In the case of Mr. Cloutier, President and Chief Operating Officer, 80% of the 125,590 Trust Units issued are subject to escrow for 4 years, released as to one quarter on each anniversary date of the transaction. The remaining Trust Units issued to non-management shareholders of the Manager were not subject to escrow restrictions. Retention bonuses paid by the Manager to three other officers were used to subscribe for 53,665 Trust Units at a price of $10.482 per Trust Unit at closing. These Trust Units are subject to the same escrow restrictions as those Trust Units issued to the President.

Prior to the acquisition, APF paid fees to the Manager equal to 3.5% of net production revenue, structuring fees of 1.5% on the purchase price of acquisitions and dispositions, as well as the right to the residual 1% royalty. The internalization resulted in the elimination of all such fees under the management agreement.

Management contract

Prior to the internalization of the management contract, the Manager handled the business of APF pursuant to a management agreement. Fees payable to Management for management, advisory and administrative services included a fee equal to 3.5% of Net Production Revenue and structuring fees of 1.5% on both the purchase price of acquisitions and on the net proceeds of dispositions. In 2003, fees paid or payable to Management on Net Production Revenues were $nil (2002 – $1,976,000) and structuring fees were $nil (2002 – $1,022,000). During 2002 structuring fees were accounted for as either part of the purchase price or as a reduction of the proceeds of disposition of oil and natural gas properties.

During the year, Energy reimbursed Management $nil (2002 – $2,294,000) for general and administrative expenses. During 2002, Energy also acquired certain non-oil and gas business assets from Management for $850,000.

During 2002, Management, through its ownership of 100% of the shares of APF, was entitled to receive 1% of the royalty income derived from the Properties. The 1% minority interest is included as an expense in the consolidated statement of operations totalling $403,000 for 2002.

NOTE 15 FINANCIAL INSTRUMENTS

APF is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Derivative instruments are used by APF to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity.

The fair values of financial instruments that are included in the balance sheet, including long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments and the floating prime rate applied to long-term borrowings.

A substantial portion of APF's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

APF has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. APF sells forward a portion of its future production through commodity swap agreements with counterparties. The following contracts were outstanding as at December 31, 2003. The estimated market value at December 31, 2003, had the contracts been settled at that time, would have resulted in a reduction of revenues otherwise to be received of $400,000.

Term	Commodity	Type of contract	Average daily quantity	Average contract price	Price index
Jan. to Mar. 2004	Crude oil	Fixed price	3,167 bbls	$U.S. 29.63	WTI
Jan. to Mar. 2004	Natural gas	Fixed price	10,000 GJ	$Cdn. 7.19	AECO
Jan. to Mar. 2004	Natural gas	Fixed price	2,000 mmbtu	$U.S. 7.00	NYMEX
Apr. to Jun. 2004	Crude oil	Fixed price	1,833 bbls	$U.S. 30.05	WTI
Jul. to Sept. 2004	Crude oil	Fixed price	1,167 bbls	$U.S. 28.86	WTI

At December 31, 2003, APF had fixed the interest rate on a portion of its debt as follows:

Term	Amount ($000)	Interest rate
January 2004 to February 2005	$20,000	3.67% plus stamping fee
January 2004 to May 2005	$20,000	3.75% plus stamping fee
January 2004 to November 2005	$20,000	3.58% plus stamping fee

The estimated market value of these interest rate contracts at December 31, 2003, had they been settled at that time, would be a cost of $900,000.

At December 31, 2003, APF had entered into the following foreign currency forward contract:

Term	Amount ($000)	Exchange rate ($Cdn./$U.S.)
January 2004 to December 2004	$U.S. 10,000	1.333

The estimated market value of these foreign currency forward contracts at December 31, 2003, had they been settled at that time, would be $nil.

NOTE 16 SUPPLEMENTAL INFORMATION FOR THE STATEMENTS OF CASH FLOWS

($000)	**2003**	2002
Cash payments related to certain items		
Interest	**4,070**	2,843
Interest on debentures	**30**	–
Distributions to minority interests	**–**	415
Distributions to Unitholders	**66,315**	36,539
Capital taxes	**3,389**	2,165

NOTE 17 CONTINGENCIES AND COMMITMENTS

APF is involved in certain legal actions that occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

APF has lease commitments relating to office buildings. The estimated annual operating lease rental payments for the building for the next five years are as follows:

($000)	
2004	773
2005	756
2006	710
2007	706
2008	359

NOTE 18 SUBSEQUENT EVENTS

Underwriting Agreement and prospectus filing

APF and the Underwriters entered into an Underwriting Agreement pursuant to which the Underwriters agreed to offer and the Trust agreed to issue and sell up to 4,765,000 Trust Units at a price of $11.60 per Trust Unit. Closing of the offering and the issue of 4,765,000 Trust Units took place on February 4, 2004. The estimated net proceeds from the offering, after deducting expenses of the issue and after Underwriters' commissions will be in the amount of $52.5 million and will be initially used to repay debt.

Five Year Review (unaudited)

	2003	2002	2001	2000	1999
FINANCIAL ($000 except per unit amounts)					
Revenue before royalties	**165,457**	94,021	69,924	44,974	24,707
Per unit basic	**$5.34**	$4.59	$5.56	$6.53	$4.19
Cash flow (1)	**83,326**	43,788	33,995	23,706	3,334
Per unit basic	**$2.69**	$2.14	$2.70	$3.44	$0.57
Net income (4)	**43,048**	11,365	18,144	14,075	(4,689)
Per unit basic	**$1.32**	$0.55	$1.44	$2.04	$(0.80)
Cash distributions	**68,713**	37,766	37,311	13,899	9,188
Per unit basic	**$2.195**	$1.810	$2.980	$1.995	$1.560
Bank debt	**98,000**	88,000	59,250	25,736	33,171
UNITS OUTSTANDING (000)					
Year-end	**34,074**	22,942	15,584	7,139	5,890
Average	**30,970**	20,470	12,578	6,888	5,890
MARKET					
High	**$12.67**	$11.19	$13.40	$10.40	$9.70
Low	**$9.30**	$9.00	$8.75	$7.00	$7.25
Close	**$12.54**	$9.79	$9.85	$9.75	$8.10
Volume (000)	**41,359**	17,314	11,645	2,520	2,394
Value ($000)	**463,074**	175,935	123,767	21,711	20,196
OPERATIONS					
Production					
Oil (bbl/d)	**6,472**	5,307	3,167	1,152	1,104
Natural gas (mcf/d)	**33,799**	18,488	15,391	13,449	13,656
NGL's (bbls/d)	**358**	144	100	254	274
Total (boe/d)	**12,463**	8,532	5,832	3,648	3,654
Annual (mboe)	**4,549**	3,114	2,129	1,335	1,334
Commodity Sales Prices (net of hedging)					
Oil ($/bbl)	**34.46**	33.66	33.64	41.40	25.00
Natural gas ($/mcf)	**6.32**	3.83	4.94	4.72	2.36
NGL's ($/bbl)	**31.82**	25.15	30.97	35.96	18.19
Average ($/boe)	**35.95**	29.65	31.94	32.98	17.74
Reserves - proved plus probable (2)					
Crude oil & NGL's (mbbl)	**23,789**	20,608	13,545	5,648	6,216
Natural gas (mmcf)	**99,197**	68,290	50,984	46,364	41,366
Total (mboe) (3)	**40,322**	31,989	22,042	13,375	13,110
ECONOMICS ($/boe)					
Average oil & gas sales price (net of hedging)	**35.95**	29.65	31.94	32.98	17.74
Other income	**0.42**	0.54	0.89	0.69	0.77
Net selling price	**36.37**	30.19	32.85	33.68	18.50
Royalties	**7.14**	6.01	6.28	6.39	2.92
Operating costs	**7.12**	6.35	6.15	6.01	5.47
Netbacks	**22.11**	17.83	20.42	21.28	10.11
General & administrative costs	**2.20**	1.49	1.58	1.38	0.85
Management fees	–	0.63	0.71	0.74	0.35
Interest	**0.92**	0.91	1.43	1.41	1.47
Taxes	**0.60**	0.61	0.55	0.12	0.07
Site restoration	**0.73**	0.67	0.61	0.68	0.48
Cash flow from operations (1)	**18.32**	14.14	15.97	17.59	7.20

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and accrued interest on convertible debentures.

(2) Reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties for 2002 and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

(3) Boe's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Net income in the basic per Trust unit calculation has been reduced by interest accrued on the convertible debentures.

Martin Hislop

Chief Executive Officer; Director

Mr. Hislop is a chartered accountant with more than 25 years' experience in all aspects of financing and managing private and public oil and gas corporations, partnerships and trusts. Prior to founding the predecessor of APF Energy in September 1994, Mr. Hislop was the President and CEO of Lakewood Energy Inc., a TSX-listed oil and gas company which was created as a result of the amalgamation of 10 limited partnerships, for whom Mr. Hislop raised in excess of $125 million in equity between 1986 and 1992. During 1984 and 1985, he provided corporate finance consulting services to a Montreal-based investment dealer. Prior to that, Mr. Hislop was Vice-President, Finance for Maxwell Cummings & Sons Holdings Ltd., a private investment company. In that capacity, he participated in the creation and/or financing of several oil and gas companies in which the Cummings group took positions, including Aberford Resources and Marine Oil. Under Mr. Hislop's stewardship, APF Energy Trust has generated an average annual rate of return of 22% since inception, placing the Trust among industry leaders.

Steve Cloutier

President and Chief Operating Officer; Director

Mr. Cloutier has more than 16 years' combined experience in oil and gas, corporate finance, mergers and acquisitions, and law. Since participating in the formation of APF Energy Trust in 1996, Mr. Cloutier has been responsible for the co-ordination of day-to-day operations of the business, and has been directly involved in oil and gas transactions worth more than $400 million. Prior to co-founding APF Energy with Mr. Hislop, Mr. Cloutier practiced law in Toronto with a firm specializing in corporate finance and secured lending. Before that, Mr. Cloutier worked in the investment industry. Mr. Cloutier is a graduate of the University of Victoria (Law) and McGill University (Labour Relations).

Bonnie Nicol

Vice President, Operations

Ms. Nicol is a professional engineer with 19 years' experience in the petroleum industry, and a broad range of expertise in operations, optimization and evaluations. Prior to joining APF in early 1998, Ms. Nicol was responsible for the Provost and Saskatchewan business unit of Northstar Energy Corporation, a senior oil and gas producer. Since graduating from the University of Alberta with a degree in chemical engineering, Ms. Nicol has assumed roles of increasing responsibility at several oil and gas companies. As the leader of the operations team, Ms. Nicol oversees a production base of more than 13,000 boe per day, and a technical staff which operates approximately 90% of its production.

R. Kenneth Pretty

Vice President, Corporate Development and Land

Mr. Pretty is a professional landman with 22 years' experience in the oil and gas industry. After graduating with an economics degree from the University of Calgary, Mr. Pretty joined Norcen Energy's land department, where he was exposed to an extensive range of mandates over a 12-year period. Mr. Pretty joined Amerada Hess in the mid-1990s in a senior land and business development position, and remained with the company following it's acquisition by Petro-Canada. In 1997, Mr. Pretty moved to Newport Petroleums as Vice President, Land, and later became Vice President, Business Development when Newport was acquired by Hunt Oil Company in 2000. He joined APF in mid-2001 and since then has been responsible for the identification, evaluation and execution of all acquisition and divestiture activities, as well as the coordination of the land function.

Alan MacDonald

Vice President, Finance

Mr. MacDonald is a chartered accountant with more than 23 years' experience in public practice and the oil and gas industry. From 1987 to 1999, Mr. MacDonald was Vice President, Finance of Starvest Capital Inc. which, among its other mandates, managed Starcor Energy Royalty Fund and Orion Energy Trust, two publicly-traded oil and gas royalty trusts. Most recently, he was Vice President, Finance of Due West Resources Inc., a private oil and gas company. In his position, Mr. MacDonald leads the team that is responsible for all financial, treasury and administrative functions for APF Energy Trust.

John Ewing

Vice President, GeoScience

Mr. Ewing is a professional geologist with more than 26 years of experience in the oil and gas industry. Following graduation with an honours degree in earth sciences from the University of Waterloo in 1978, Mr. Ewing began his career with Husky Oil. After working in both technical and managerial positions at several oil and gas companies, Mr. Ewing joined Tethys Energy Inc. in 1996, as Vice President, Exploration, where he oversaw an exploration program that contributed to the growth of the company from 650 boe/d in late 1996 to 3,400 boe/d by early 2000. Prior to joining APF, Mr. Ewing was President of a private resources and consulting firm. In his position, Mr. Ewing is responsible for overseeing the geological and geophysical aspects of APF Energy Trust.

Dan Allan

Vice President, Coalbed Methane

Mr. Allan is a professional geologist registered in both Alberta and the state of Wyoming, with more than 28 years of experience in the oil and gas industry. Following graduation with an honours degree in geology from McGill University in 1975, Mr. Allan began his career with Texaco Exploration, where he spent six years in Western Canada. In 1981 he moved to Dome Petroleum in Denver, Colorado and spent the next 14 years in the U.S. In 1994 he commenced employment with MAXX Petroleum as Exploration Manager and subsequently founded CanScot Resources Ltd. in 1997 as President and CEO. CanScot was acquired by APF in September of 2003. In recent years, Mr. Allan has become involved in coalbed methane ("CBM") exploration and development in both Canada and the U.S. In his position, Mr. Allan is responsible for overseeing the CBM division at APF Energy Trust.

Don Engle

Independent Director and Chairman of the Board

Board Committees: Audit, Reserves, Compensation

Mr. Engle has been President of Sapphire Resources Ltd., a private oil and gas consulting company since 1985. Since September, 2003 Mr. Engle has been Director and Chief Operating Officer of Welton Energy Corporation, a junior oil and gas company. From 1996 – 2000, Mr. Engle was President of Grey Wolf Exploration Inc., a publicly traded oil and gas company listed on the Toronto Stock Exchange. Mr. Engle is a professional landman, with more than 34 years of experience in the petroleum industry.

William Dickson

Independent Director

Board Committees: Audit, Reserves

Mr. Dickson brings to APF Energy Trust more than 45 years' of technical, management and public company experience in the oil and gas industry. He is active as principal of Arlyn Enterprises Ltd., a private lubricants company and serves on the Board of IMS Petroleum Ltd. Previously, he has held senior executive and/or Board positions with Stampeder Exploration Ltd., Ultramar Oil and Gas Canada Ltd., and numerous non-profit societies.

Daniel Mercier

Independent Director

Board Committees: Audit, Reserves, Compensation

Mr. Mercier is a professional engineer with extensive experience in the operation, management and capitalization of oil and gas companies. Throughout the past nine years he has been President of Asia Energy Ltd., a private Alberta corporation which he initiated in 1995 that holds interests in Russia. Since September, 1998, Mr. Mercier has been Vice President, Operations for SOCO International plc, a publicly traded United Kingdom corporation engaged in international oil and natural gas exploration and production. Prior to that, he was Chairman, Chief Executive Officer and a Director of Territorial Resources Inc., a publicly traded U.S. oil and gas exploration company which merged with SOCO. From January of 1996 to March of 1996, Mr. Mercier was employed by Chancellor Energy Resources Inc. as Chief Operating Officer to assist with the sale of the company to HCO Energy Ltd. Prior to January of 1996, he was President and Chief Executive Officer of Canadian Conquest Explorations Inc. Each of Chancellor, HCO and Canadian Conquest were publicly listed Alberta corporations.

Robert MacDonald

Independent Director

Board Committees: Audit, Reserves

Mr. MacDonald was a Director, Commercial Banking, CIBC World Markets, a subsidiary of a Canadian Chartered Bank from October 1998 to May 2003. From March 1998 to October 1998 he was Managing Director, Koch Capital, the merchant banking arm of a private U.S. based energy company. From 1993 to March 1998, Mr. MacDonald was Vice President, Oil & Gas Group, Canadian Imperial Bank of Commerce. Prior to that, he spent 17 years in other positions within the financial services industry.

Corporate Information

HEAD OFFICE
2100, 144 Fourth Avenue S.W.
Calgary, Alberta T2P 3N4
Tel: (403)294-1000
Toll Free: (800) 838-9206
Fax: (403) 294-1074
Email: invest@apfenergy.com
www.apfenergy.com

FIELD OFFICE
400 King Street
Estevan, Saskatchewan S4A 2B4
Tel: (306) 634-0066
Fax: (306) 634-0077

LEGAL COUNSEL
Parlee McLaws, LLP

BANK
National Bank of Canada

ENGINEERING CONSULTANTS
Gilbert Lausten Jung Associates Ltd.
McDaniels & Associates Consultants Ltd.

TRUSTEE, REGISTRAR AND TRANSFER AGENT
Computershare Trust Company of Canada

AUDITORS
PricewaterhouseCoopers LLP

STOCK EXCHANGE LISTING
Toronto Stock Exchange
Symbols: AY.UN and AY.DB

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbl	barrel
bcf	billion cubic feet
boe	barrels of oil equivalent*
boe/d	barrels of oil equivalent per day*
CBM	coalbed methane
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent*
mmboe	million barrels of oil equivalent*
mmbtu	million British thermal units
mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
NGL	natural gas liquid
NPV	net present value
P+P	proved plus probable
tcf	trillion cubic feet
WTI	West Texas Intermediate

*6 mcf of gas = 1 barrel of oil

DIRECTORS AND OFFICERS

Don Engle
Independent Director and
Chairman of the Board (1) (2) (3)

William Dickson
Independent Director (1) (3)

Daniel Mercier
Independent Director (1) (2) (3)

Robert MacDonald
Independent Director (1) (3)

Martin Hislop
Director
Chief Executive Officer

Steven Cloutier (2)
Director
President & Chief Operating Officer

Bonnie Nicol
Vice President, Operations

Ken Pretty
Vice President, Corporate Development and Land

Alan MacDonald
Vice President, Finance

John Ewing
Vice President, GeoScience

Dan Allan
Vice President, Coalbed Methane

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Reserves Committee

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APF ENERGY

2100, 144 Fourth Avenue S.W.
Calgary, Alberta T2P 3N4
Tel: (403)294-1000
Toll Free: (800) 838-9206
Fax: (403) 294-1074
Email: invest@apfenergy.com
www.apfenergy.com

No marmots were harmed in the making of this annual report.

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